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Company: HESS CORP

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FWE-0040076

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2020
or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _____ to _____
Commission File Number 1-1204

Hess Corporation

(Exact name of Registrant as specified in its charter)

DELAWARE

(State or other jurisdiction of
incorporation or organization)

**1185 AVENUE OF THE AMERICAS,
NEW YORK, NY**

(Address of principal executive offices)

13-4921002

(I.R.S. Employer

Identification Number)

10036

(Zip Code)

Registrant's telephone number, including area code (212) 997-8500

Securities registered pursuant to Section 12(b) of the Act:

<i>Title of Each Class</i>	<i>Trading Symbol(s)</i>	<i>Name of Each Exchange on Which Registered</i>
Common Stock (par value \$1.00)	HES	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☒

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the Registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," - "smaller reporting company" and "emerging growth company" - in Rule 12b-2 of the Exchange Act:

Large accelerated filer	<input checked="" type="checkbox"/>	Accelerated filer	<input type="checkbox"/>
Non-accelerated filer	<input type="checkbox"/>	Smaller reporting company	<input type="checkbox"/>
Emerging Growth Company	<input type="checkbox"/>		

If an emerging growth company, indicate by check mark if the Registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. Yes ☒ No ☐

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of voting stock held by non-affiliates of the Registrant amounted to \$14,091,000,000, computed using the outstanding Common Stock and closing market price on June 30, 2020, the last business day of the Registrant's most recently completed second fiscal quarter.

At January 31, 2021, there were 306,986,553 shares of Common Stock outstanding.

Part III is incorporated by reference from the Proxy Statement for the 2021 annual meeting of stockholders.

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HESS CORPORATION
Form 10-K
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Unless the context indicates otherwise, references to "Hess", the "Corporation", "Registrant", "we", "us", "our" and "its" refer to the consolidated business operations of Hess Corporation and its subsidiaries.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K, including information incorporated by reference herein, contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Words such as "anticipate," "estimate," "expect," "forecast," "guidance," "could," "may," "should," "would," "believe," "intend," "project," "plan," "predict," "will," "target" and similar expressions identify forward-looking statements, which are not historical in nature. Our forward-looking statements may include, without limitation: our future financial and operational results; our business strategy; estimates of our crude oil and natural gas reserves and levels of production; benchmark prices of crude oil, natural gas liquids and natural gas and our associated realized price differentials; our projected budget and capital and exploratory expenditures; expected timing and completion of our development projects; and future economic and market conditions in the oil and gas industry.

Forward-looking statements are based on our current understanding, assessments, estimates and projections of relevant factors and reasonable assumptions about the future. Forward-looking statements are subject to certain known and unknown risks and uncertainties that could cause actual results to differ materially from our historical experience and our current projections or expectations of future results expressed or implied by these forward-looking statements. The following important factors could cause actual results to differ materially from those in our forward-looking statements:

- fluctuations in market prices of crude oil, natural gas liquids and natural gas and competition in the oil and gas exploration and production industry, including as a result of the global COVID-19 pandemic (COVID-19);

- reduced demand for our products, including due to COVID-19 or the outbreak of any other public health threat, or due to the impact of competing or alternative energy products and political conditions and events;
- potential failures or delays in increasing oil and gas reserves, including as a result of unsuccessful exploration activity, drilling risks and unforeseen reservoir conditions, and in achieving expected production levels;
- changes in tax, property, contract and other laws, regulations and governmental actions applicable to our business, including legislative and regulatory initiatives regarding environmental concerns, such as measures to limit greenhouse gas emissions and flaring as well as fracking bans;
- disruption or interruption of our operations due to catastrophic events, such as accidents, severe weather, geological events, shortages of skilled labor, cyber-attacks or health measures related to COVID-19;
- the ability of our contractual counterparties to satisfy their obligations to us, including the operation of joint ventures under which we may not control;
- unexpected changes in technical requirements for constructing, modifying or operating exploration and production facilities and/or the inability to timely obtain or maintain necessary permits;
- availability and costs of employees and other personnel, drilling rigs, equipment, supplies and other required services;
- any limitations on our access to capital or increase in our cost of capital, including as a result of weakness in the oil and gas industry or negative outcomes within commodity and financial markets;
- liability resulting from litigation, including heightened risks associated with being a general partner of Hess Midstream LP; and
- other factors described in Item 1A—Risk Factors in this Annual Report on Form 10-K and any additional risks described in our other filings with the Securities and Exchange Commission.

As and when made, we believe that our forward-looking statements are reasonable. However, given these risks and uncertainties, caution should be taken not to place undue reliance on any such forward-looking statements since such statements speak only as of the date when made and there can be no assurance that such forward-looking statements will occur and actual results may differ materially from those contained in any forward-looking statement we make. Except as required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether because of new information, future events or otherwise.

Glossary

Throughout this report, the following company or industry specific terms and abbreviations are used:

Appraisal well – An exploration well drilled to confirm the results of a discovery well, or a well that is used to determine the boundaries of a productive formation.

Bbl – One stock tank barrel, which is 42 United States gallons liquid volume.

Barrel of oil equivalent or Boe – This reflects natural gas reserves converted on the basis of relative energy content of six mcf equals one barrel of oil equivalent (one mcf represents one thousand cubic feet). Barrel of oil equivalence does not necessarily result in price equivalence, as the equivalent price of natural gas on a barrel of oil equivalent basis has been substantially lower than the corresponding price for crude oil over the recent past.

Boepd – Barrels of oil equivalent per day.

Bopd – Barrels of oil per day.

CGA – Clean Gulf Associates.

Condensate – A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that when produced, is in the liquid phase at surface pressure and temperature.

DAPL – Dakota Access Pipeline.

DD&A – Depreciation, depletion and amortization.

Development well – A well drilled within the proved area of an oil and/or natural gas reservoir with the intent of producing oil and/or natural gas from that area of the reservoir.

Dry hole – An exploratory or development well that does not find oil or natural gas in commercial quantities.

EPA – Environmental Protection Agency.

EHS & SR – Environment, health, safety and social responsibility.

Exploratory well – A well drilled to find oil or natural gas in an unproved area or find a new reservoir in a field previously found to be productive by another reservoir.

E&P – Exploration and Production.

Fractionation – A process by which the mixture of natural gas liquids that results from natural gas processing is separated into the NGL components, such as ethane, propane, butane, isobutane, and natural gasoline, prior to their sale to various petrochemical and industrial end users. Fractionation is accomplished by controlling the temperature of the stream of mixed liquids in order to take advantage of the difference in boiling points of separate products.

Field – An area consisting of a single reservoir or multiple reservoirs all grouped or related to the same individual geological structural feature and/or stratigraphic condition.

FPSO – Floating production, storage, and offloading vessel.

GHG – Greenhouse gas.

Gross acres – Acreage in which a working interest is held by the Corporation.

Gross well – A well in which a working interest is held by the Corporation.

ICE – Integrity critical equipment.

JOA – Joint operating agreement.

LIBOR – The London Interbank Offered Rate.

Mcf – One thousand cubic feet of natural gas.

Mmcfd – One thousand mcf of natural gas per day.

MWCC – Marine Well Containment Company.

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MSRC – Marine Spill Response Corporation.

MTBE – Methyl tertiary butyl ether.

Net acreage or Net wells – The sum of the fractional working interests owned by the Corporation in gross acres or gross wells.

NGL or Natural gas liquids – Naturally occurring hydrocarbon substances that are separated and produced by fractionating natural gas, including ethane, butane, isobutane, propane and natural gasoline. NGL do not sell at prices equivalent to crude oil.

Non-operated – Projects in which the Corporation has a working interest but does not perform the role of Operator.

OPEC – Organization of Petroleum Exporting Countries.

Operator – The entity responsible for conducting and managing exploration, development, and/or production operations for an oil or gas project.

OSHA – Occupational Safety and Health Administration.

OSRL – Oil Spill Response Limited.

Plug and perf completion – A well completion technique which involves creating perforations in the well casing that penetrate the hydrocarbon reservoir section between set plugs.

Participating interest – Reflects the proportion of exploration and production costs each party will bear as set out in an operating agreement.

Production sharing contract – An agreement between a host government and the owners (or co-owners) of a well or field regarding the percentage of production each party will receive after the parties have recovered a specified amount of capital and operational expenses.

Productive well – A well that is capable of producing hydrocarbons in sufficient quantities to justify commercial exploitation.

Proved properties – Properties with proved reserves.

Proved reserves – In accordance with the Securities and Exchange Commission regulations and practices recognized in the publication of the Society of Petroleum Engineers entitled, “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information,” those quantities of crude oil and condensate, NGL and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions,

operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Proved developed reserves – Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or for which the cost of the required equipment is relatively minor compared to the cost of a new well.

Proved undeveloped reserves – Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

SOFR – Secured Overnight Financing Rate.

Unproved properties – Properties with no proved reserves.

VLCC – Very large crude carrier.

Working interest – An interest in an oil and gas property that provides the owner of the interest the right to participate in the drilling for and production of oil and gas on the relevant acreage and requires the owner to pay a share of the costs of drilling and production operations.

WWC – Wild Well Control.

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PART I

Items 1 and 2. Business and Properties

Hess Corporation, incorporated in the State of Delaware in 1920, is a global E&P company engaged in exploration, development, production, transportation, purchase and sale of crude oil, natural gas liquids, and natural gas with production operations located primarily in the United States (U.S.), Guyana, the Malaysia/Thailand Joint Development Area (JDA), Malaysia, and Denmark. We conduct exploration activities primarily offshore Guyana, in the U.S. Gulf of Mexico, and offshore Suriname and Canada. At the Stabroek Block (Hess 30%), offshore Guyana, we have announced eighteen significant discoveries. The Liza Phase 1 development achieved first production in December 2019, and reached its nameplate production capacity of approximately 120,000 gross bopd in December 2020. The Liza Phase 2 development was sanctioned in the second quarter of 2019 and is expected to achieve first production by early 2022, with production capacity of approximately 220,000 gross bopd. A third development, Payara, was sanctioned in the third quarter of 2020 and is expected to achieve first production in 2024, with production capacity of approximately 220,000 gross bopd. The discovered resources to date on the Stabroek Block are expected to underpin up to ten FPSOs with the first five FPSOs producing more than 750,000 gross bopd by 2026.

Our Midstream operating segment, which is comprised of Hess Corporation's 47% consolidated ownership interest in Hess Midstream LP at December 31, 2020, provides fee-based services, including gathering, compressing and processing natural gas and fractionating NGL; gathering, terminaling, loading and transporting crude oil and NGL; storing and terminaling propane, and water handling services primarily in the Bakken shale play in the Williston Basin area of North Dakota. See *Midstream* on page 12.

Exploration and Production

Proved Reserves

Proved reserves are calculated using the average price during the twelve-month period ending December 31 determined as an unweighted arithmetic average of the price on the first day of each month within the year, unless prices are defined by contractual agreements, and exclude escalations based on future conditions. Crude oil prices used in the determination of proved reserves at December 31, 2020 were \$39.77 per barrel for West Texas Intermediate (WTI) (2019: \$55.73) and \$43.43 per barrel for Brent (2019: \$62.54). Our total proved developed and undeveloped reserves at December 31 were as follows:

	Crude Oil & Condensate		Natural Gas Liquids		Natural Gas		Total Barrels of Oil Equivalent (BOE)	
	2020	2019	2020	2019	2020	2019	2020	2019
	(Millions of bbls)		(Millions of bbls)		(Millions of mcf)		(Millions of bbls)	
Developed								
United States	282	293	120	90	490	400	484	450
Guyana (a)	72	31	—	—	36	3	78	31
Malaysia and JDA	4	5	—	—	543	497	94	88
Other (b)	134	139	—	—	165	183	162	170
	492	468	120	90	1,234	1,083	818	739

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Undeveloped

United States	119	215	42	79	163	300	188	344
Guyana (a)	132	55	—	—	47	4	140	56
Malaysia and JDA	2	2	—	—	132	188	24	33
Other (b)	—	22	—	—	—	18	—	25
	<u>253</u>	<u>294</u>	<u>42</u>	<u>79</u>	<u>342</u>	<u>510</u>	<u>352</u>	<u>458</u>

Total

United States	401	508	162	169	653	700	672	794
Guyana (a)	204	86	—	—	83	7	218	87
Malaysia and JDA	6	7	—	—	675	685	118	121
Other (b)	134	161	—	—	165	201	162	195
	<u>745</u>	<u>762</u>	<u>162</u>	<u>169</u>	<u>1,576</u>	<u>1,593</u>	<u>1,170</u>	<u>1,197</u>

(a) Guyana natural gas reserves will be consumed for fuel.

(b) Other includes our interests in Denmark and Libya. At December 31, 2020, total proved reserves for Denmark and Libya were 40 million boe and 122 million boe, respectively. At December 31, 2019, total proved reserves for Denmark and Libya were 54 million boe and 141 million boe, respectively.

Proved undeveloped reserves were 30% of our total proved reserves at December 31, 2020 on a boe basis (2019: 38%). Proved reserves held under production sharing contracts totaled 28% of our crude oil reserves and 48% of our natural gas reserves at December 31, 2020 (2019: 12% and 43%, respectively).

For additional information regarding our proved oil and gas reserves, see the *Supplementary Oil and Gas Data* to the *Consolidated Financial Statements* presented on pages 91 through 99.

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Production

Worldwide crude oil, NGL, and natural gas net production was as follows:

	2020	2019	2018
Crude oil – Thousands of barrels			
United States			
North Dakota	39,047	34,299	28,052
Offshore (a)	13,961	16,628	15,026
Total United States	53,008	50,927	43,078
Guyana	7,457	67	—
Malaysia and JDA	1,287	1,479	1,397
Other (b)	3,358	9,161	8,885
Total	65,110	61,634	53,360
Natural gas liquids – Thousands of barrels			
United States			
North Dakota	20,514	15,150	11,497
Other Onshore (c)	—	—	917
Total Onshore	20,514	15,150	12,414
Offshore (a)	1,878	1,942	1,703
Total United States	22,392	17,092	14,117
Natural gas – Thousands of mcf			
United States			
North Dakota	65,786	40,222	27,740
Other Onshore (c)	—	—	14,052
Total Onshore	65,786	40,222	41,792
Offshore (a)	27,985	33,212	24,452
Total United States	93,771	73,434	66,244
Malaysia and JDA	106,618	128,071	128,472
Other (b)	2,540	7,144	7,246
Total	202,929	208,649	201,962
Total Barrels of Oil Equivalent (in millions) (a) (b) (c)	<u>121</u>	<u>114</u>	<u>101</u>

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- (a) In November 2020, we sold our working interest in the Shenzi Field in the deepwater Gulf of Mexico. Shenzi net production was 3.3 million boe in 2020 (2019: 4.5 million boe; 2018: 5.8 million boe).
- (b) Other includes our interests in Denmark and Libya. Net production from Libya was 1.6 million boe for 2020 (2019: 7.8 million boe; 2018: 7.4 million boe). Net production from Denmark was 2.2 million boe for 2020 (2019: 2.6 million boe; 2018: 2.7 million boe).
- (c) In August 2018, we sold our interests in the Utica shale play, onshore U.S. Utica net production was 3.3 million boe in 2018.

E&P Operations

At December 31, 2020, our significant E&P assets included the following:

United States

Our production in the U.S. was from the Bakken shale play in the Williston Basin of North Dakota (Bakken) and from offshore properties in the Gulf of Mexico.

North Dakota:

Bakken: At December 31, 2020, we held approximately 532,000 net acres in the Bakken with varying working interest percentages. Net production averaged 193,000 boepd in 2020. We operated six rigs in the Bakken through May, before reducing to one rig for the remainder of 2020 in response to the sharp decline in oil prices resulting from the COVID-19 pandemic. We drilled 71 wells and brought 111 wells on production, bringing the total operated production wells to 1,686 by year-end. We reduced the average cost of a plug and perf well in 2020 to \$6.2 million per well from \$6.8 million per well in 2019.

During 2021, we plan to operate two rigs, drill approximately 55 wells and bring approximately 45 wells on production. We forecast net production to average approximately 170,000 boepd for the full year 2021. In 2021, the Tioga Gas Plant will be shut down for approximately 45 days for a planned maintenance turnaround and tie-in of the plant expansion project completed in 2020 which will increase gas processing capacity to 400 million cubic feet per day from 250 million cubic feet per day. The shutdown is expected to reduce 2021 average net production, mostly natural gas, by approximately 7,500 boepd.

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Offshore:

Gulf of Mexico: At December 31, 2020, we held approximately 61,000 net developed acres, with our production operations principally at the Baldpate (Hess 50%), Conger (Hess 38%), Hack Wilson (Hess 25%), Llano (Hess 50%), Penn State (Hess 50%), Stampede (Hess 25%) and Tubular Bells (Hess 57%) fields. At December 31, 2020, we held approximately 286,000 net undeveloped acres, of which leases covering approximately 112,000 acres are due to expire in the next three years.

In November 2020, we completed the sale of our 28% working interest in the Shenzi Field for net proceeds of \$482 million, after closing adjustments. Our net share of production from the Shenzi Field during 2020 was 9,000 boepd.

We participated in two outside operated exploration wells that were completed in 2020, the Oldfield-1 well and the Galapagos Deep well, both located in the Mississippi Canyon area. Both wells were unsuccessful.

Guyana

Stabroek Block: The Stabroek Block (Hess 30%), offshore Guyana, covers approximately 6.6 million acres. The operator, Esso Exploration and Production Guyana Limited, has made eighteen significant discoveries since 2015. The discovered resources to date on the Stabroek Block are expected to underpin the potential for up to ten FPSOs with the first five FPSOs producing more than 750,000 gross bopd by 2026.

The Liza Phase 1 development, which was sanctioned in 2017, began producing oil in December 2019 from the Liza Destiny FPSO and reached its nameplate production capacity of 120,000 gross bopd in December 2020. The Liza Phase 2 development was sanctioned in 2019 and will utilize the Liza Unity FPSO to produce up to 220,000 gross bopd, with first production expected by early 2022. A total of 30 wells are planned at six drill centers, including 15 production wells, nine water injection wells and six gas injection wells. In 2021, the operator plans to continue development drilling, complete installation of subsea flow lines and equipment, complete installation of topside facilities on the FPSO and sail the Liza Unity FPSO from Singapore to the Liza Field.

On September 30, 2020, we announced the final investment decision to proceed with development of the Payara Field on the Stabroek Block after the development plan received approval from the government of Guyana. Payara will utilize the Prosperity FPSO, which will have the capacity to produce up to 220,000 gross bopd, with first production expected in 2024. Ten drill centers with a total of 41 wells are planned, including 20 production wells and 21 injection wells. Excluding pre-sanction costs and FPSO purchase cost, our net share of development costs is forecast to be approximately \$1.8 billion.

The operator is currently utilizing four drillships for exploration, appraisal and development drilling activities, and intends to bring in a fifth and sixth drillship in 2021.

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In 2020, the following exploration and appraisal wells were drilled on the Stabroek Block (in chronological order):

Uaru: The Uaru-1 well encountered approximately 94 feet of high-quality oil-bearing sandstone reservoir and is located approximately 10 miles northeast of the Liza Field.

Yellowtail: The Yellowtail-2 well encountered approximately 69 feet of high-quality oil-bearing reservoirs and is located adjacent to and below the Yellowtail-1 discovery.

Redtail: The Redtail-1 well encountered approximately 232 feet of high-quality oil-bearing sandstone and is located approximately 1.5 miles northwest of the Yellowtail discovery.

In 2021, the operator completed drilling of the Hassa-1 well. The Hassa-1 well encountered approximately 50 feet of oil bearing reservoir in deeper geologic intervals, although the well did not encounter oil in the primary target areas. The operator plans to drill an additional 12 to 15 exploration and appraisal wells in 2021 that will target a variety of prospects and play types. These will include both lower risk wells near existing discoveries and higher risk step-out wells, and several penetrations that will test deeper Lower Campanian and Santonian intervals.

Kaieteur Block: In 2018, we acquired a participating interest in the Kaieteur Block (Hess 15%), which is adjacent to the Stabroek Block. In 2020, the operator, Esso Exploration and Production Guyana Limited, completed drilling of the Tanager-1 exploration well. The well did encounter hydrocarbons but was not a commercial success on a stand-alone basis.

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Malaysia and JDA

Malaysia/Thailand Joint Development Area (JDA): Production comes from the Carigali Hess operated Block A-18 in the Malaysia/Thailand joint development area in the Gulf of Thailand (Hess 50%). A multi-year drilling program is planned to commence in the first half of 2021.

Malaysia: Our production in Malaysia comes from our interest in Block PM302 (Hess 50%) located in the North Malay Basin (NMB), offshore Peninsular Malaysia and Block PM301 (Hess 50%), which is adjacent to and is unitized with Block A-18 of the JDA. In 2021, we plan to continue drilling and development activities at NMB.

Other

Denmark: Production comes from our operated interest in the South Arne Field (Hess 62%).

Libya: At the onshore Waha concession in Libya, which includes the Defa, Faregh, Gialo, North Gialo and Belhedan fields (Hess 8%), net production averaged 4,000 boepd in 2020, 21,000 boepd in 2019 and 20,000 boepd in 2018. Production was shut-in by the operator between January and October of 2020 due to force majeure caused by civil unrest. The Company's net investment in Libya was approximately \$85 million at December 31, 2020.

Suriname: We hold a 33% non-operated participating interest in Block 42, offshore Suriname. In 2022, the operator, a subsidiary of Royal Dutch Shell plc, plans to drill an exploration well. We also hold a 33% non-operated participating interest in Block 59, offshore Suriname, where the operator, ExxonMobil Exploration and Production Suriname B.V., is interpreting recently acquired 2D seismic and is planning a 3D seismic acquisition.

Canada: We hold a 50% non-operated participating interest in four exploration licenses offshore Nova Scotia and a 25% non-operated participating interest in three exploration licenses offshore Newfoundland. In 2023, the operator, BP Canada, plans to drill one exploration well in Newfoundland.

Sales Commitments

We have certain long-term contracts with fixed minimum sales volume commitments for natural gas and NGL production. At the JDA in the Gulf of Thailand, we have annual minimum net sales commitments of approximately 80 billion cubic feet of natural gas per year through 2025 and approximately 40 billion cubic feet per year in 2026 and 2027. At the North Malay Basin development project offshore Peninsular Malaysia, we have annual net sales commitments of approximately 55 billion cubic feet per year through 2024. Our estimated total volume of production subject to these sales commitments is approximately 710 billion cubic feet of natural gas. We also have multiple minimum delivery commitments in the Bakken for natural gas and NGL with various end dates up through 2032, with total commitments of approximately 100 million boe over the remaining life of the contracts.

We have not experienced any significant constraints in satisfying the committed quantities required by our sales commitments, and we anticipate being able to meet future requirements from available proved and probable reserves, as well as projected third-party supply in the case of NGL.

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Selling Prices and Production Costs

The following table presents our average selling prices and average production costs:

	2020	2019	2018
Average Selling Prices (a)			
Crude Oil - Per Barrel (Including Hedging)			
United States			
North Dakota	\$ 42.63	\$ 53.19	\$ 56.90
Offshore	45.92	59.18	62.02
Total United States	43.56	55.15	58.69
Guyana	46.41	—	—
Malaysia and JDA	37.91	61.81	70.42
Other (b)	51.37	65.22	69.76
Worldwide	44.28	56.77	60.77
Crude Oil - Per Barrel (Excluding Hedging)			
United States			
North Dakota	\$ 33.87	\$ 53.18	\$ 60.64
Offshore	36.55	59.17	65.73
Total United States	34.63	55.14	62.41
Guyana	37.40	—	—
Malaysia and JDA	37.91	61.81	70.42
Other (b)	43.42	65.22	69.76
Worldwide	35.52	56.76	63.80
Natural Gas Liquids - Per Barrel			
United States			
North Dakota	\$ 11.29	\$ 13.20	\$ 21.48
Other Onshore (c)	—	—	18.55
Offshore	8.94	13.31	25.58
Worldwide	11.10	13.21	21.81
Natural Gas - Per Mcf			
United States			
North Dakota	\$ 1.27	\$ 1.59	\$ 2.42
Other Onshore (c)	—	—	2.02
Offshore	1.23	2.12	2.68
Total United States	1.26	1.83	2.43
Malaysia and JDA	4.47	5.04	5.07
Other (b)	3.41	4.63	4.41
Worldwide	2.98	3.90	4.18
Average production (lifting) costs per barrel of oil equivalent produced (d)			
United States			
North Dakota (e)	\$ 17.67	\$ 19.68	\$ 23.00
Other Onshore (c)	—	—	14.32
Offshore	11.27	11.27	13.80
Total United States	16.59	17.66	19.74
Guyana (f)	18.25	—	—
Malaysia and JDA	5.77	6.07	5.65
Other (b)	22.78	8.87	9.04
Worldwide	15.19	14.93	15.73

(a) Includes inter-company transfers valued at approximate market prices, primarily onshore U.S., which include certain processing and distribution fees.

(b) Other includes our interests in Denmark and Libya.

(c) In August 2018, we sold our interests in the Utica shale play, onshore U.S.

(d) Production (lifting) costs consist of amounts incurred to operate and maintain our producing oil and gas wells, related equipment and facilities and transportation costs, including Midstream tariff expense. Lifting costs do not include costs of finding and developing proved oil and gas reserves, production and severance taxes, or the costs of related general and administrative expenses, interest expense and income taxes.

(e) Includes Midstream tariff expense of \$13.42 per boe in 2020 (2019: \$12.89 per boe; 2018: \$14.72 per boe).

(f) Includes pre-development costs from the operator for future phases of development and Hess internal costs totaling \$5.11 per boe.

Gross and Net Undeveloped Acreage

At December 31, 2020, gross and net undeveloped acreage amounted to:

	Undeveloped	
	Acreage (a)	
	Gross	Net
	(In thousands)	
United States	333	300
Guyana	9,873	2,461
Malaysia and JDA	655	327
Denmark	9	1
Libya	3,334	272
Canada	3,405	1,283
Suriname	4,363	1,454
Total (b)	21,972	6,098

(a) Includes acreage held under production sharing contracts.

(b) At December 31, 2020, 59% of our net undeveloped acreage, primarily in Suriname, Canada, and Guyana, is scheduled to expire during the next three years pending results of exploration activities.

Gross and Net Developed Acreage, and Productive Wells

At December 31, 2020 gross and net developed acreage and productive wells amounted to:

	Developed Acreage Applicable to Productive Wells		Productive Wells (a)			
			Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
	(In thousands)					
United States	967	578	3,061	1,424	11	5
Guyana	95	29	6	2	—	—
Malaysia and JDA	454	227	—	—	129	62
Denmark	23	14	18	11	—	—
Libya	9,564	782	1,123	92	10	1
Total	11,103	1,630	4,208	1,529	150	68

(a) Includes multiple completion wells (wells producing from different formations in the same bore hole) totaling 24 gross wells and 21 net wells.

Exploratory and Development Wells

Net exploratory and net development wells completed during the years ended December 31 were:

	Net Exploratory Wells			Net Development Wells		
	2020	2019	2018	2020	2019	2018
Productive wells						
United States	—	—	—	98	140	92
Guyana	1	2	2	—	2	—
Malaysia and JDA	—	—	2	3	3	1
Libya	—	—	—	—	2	—
	1	2	4	101	147	93
Dry holes						
United States	1	—	—	—	—	—
Guyana (a)	—	—	—	—	—	—
Malaysia and JDA	—	—	1	—	—	—
Denmark	—	1	—	—	—	—
Suriname (b)	—	—	—	—	—	—
Canada	—	—	1	—	—	—
	1	1	2	—	—	—
Total	2	3	6	101	147	93

(a) Includes the Tanager-1 well at the Kaieteur Block, offshore Guyana in 2020 and the Sorubim-1 well at the Stabroek Block, offshore Guyana in 2018.

(b) Includes the Pontoenoe-1 well in Block 42, offshore Suriname in 2018.

Number of Wells in the Process of Being Drilled

At December 31, 2020, the number of wells in the process of drilling amounted to:

	Gross Wells	Net Wells
United States	187	34
Guyana (a)	18	5
Libya	8	1
Total	213	40

(a) Includes ten gross (and three net) water injection and gas injection wells in process at December 31, 2020.

Midstream

Prior to December 16, 2019, the Midstream segment was primarily comprised of Hess Infrastructure Partners LP (HIP), a 50/50 joint venture between Hess Corporation and Global Infrastructure Partners (GIP), formed to own, operate, develop and acquire a diverse set of midstream assets to provide fee-based services to Hess and third-party customers. HIP was initially formed on May 21, 2015, with Hess selling 50% of HIP to GIP for approximately \$2.6 billion on July 1, 2015.

On April 10, 2017, HIP completed an initial public offering (IPO) of 16,997,000 common units, representing 30.5% limited partnership interests in its subsidiary Hess Midstream Partners LP (Hess Midstream Partners), for net proceeds of approximately \$365.5 million. In connection with the IPO, HIP contributed a 20% controlling economic interest in each of Hess North Dakota Pipeline Operations LP, Hess TGP Operations LP, and Hess North Dakota Export Logistics Operations LP, and a 100% economic interest in Hess Mentor Storage Holdings LLC (collectively the “Contributed Businesses”). In exchange for the contributed businesses, Hess and GIP each received common and subordinated units representing a direct 33.75% limited partner interest in Hess Midstream Partners and a 50% indirect ownership interest through HIP in Hess Midstream Partners’ general partner, which had a 2% economic interest in Hess Midstream Partners plus incentive distribution rights.

On March 1, 2019, HIP acquired Hess’s existing Bakken water services business for \$225 million in cash. As a result of this transaction, we recorded an after-tax gain of \$78 million in additional paid-in capital with an offsetting reduction to noncontrolling interest to reflect the adjustment to GIP’s noncontrolling interest in HIP. On March 22, 2019, HIP and Hess Midstream Partners acquired crude oil and gas gathering assets, and HIP acquired water gathering assets of Summit Midstream Partners LP’s Tioga Gathering System for aggregate cash consideration of approximately \$90 million, with the potential for up to an additional \$10 million of contingent payments in future periods subject to certain future performance metrics. On January 25, 2018, Hess Midstream Partners entered into a 50/50 joint venture with Targa Resources Corp. to construct a new 200 million standard cubic feet per day gas processing plant call Little Missouri 4. The plant, which is operated by Targa, was placed into service in the third quarter of 2019.

On December 16, 2019, Hess Midstream Partners acquired HIP, including HIP’s 80% interest in Hess Midstream Partners’ oil and gas midstream assets, HIP’s water services business and the outstanding economic general partner interest and incentive distribution rights in Hess Midstream Partners LP. In addition, Hess Midstream Partners’ organizational structure converted from a master limited partnership into an “Up-C” structure in which Hess Midstream Partners’ public unitholders received newly issued Class A shares in a new public entity named Hess Midstream LP (Hess Midstream), which is taxed as a corporation for U.S. federal and state income tax purposes. Hess Midstream Partners changed its name to “Hess Midstream Operations LP” (HESM Opco) and became a consolidated subsidiary of Hess Midstream, the new publicly listed entity. As consideration for the acquisition, Hess received a cash payment of \$301 million and approximately 115 million newly issued HESM Opco Class B units. After giving effect to the acquisition and related transactions, public shareholders of Class A shares in Hess Midstream own 6% of the consolidated entity on an as-exchanged basis and Hess and GIP each own 47% of the consolidated entity on an as-exchanged basis, primarily through the sponsors’ ownership of Class B units in HESM Opco that are exchangeable into Class A shares of Hess Midstream on a one-for-one basis, or referred to as “Hess Corporation’s 47% consolidated ownership interest in Hess Midstream LP”.

At December 31, 2020, Midstream assets included the following:

- **Natural Gas Gathering and Compression:** A natural gas gathering and compression system located primarily in McKenzie, Williams and Mountrail Counties, North Dakota connecting Hess and third-party owned or operated wells to the Tioga Gas Plant, Little Missouri 4 Gas Plant, and third-party pipeline facilities. This gathering system consists of approximately 1,350 miles of high and low pressure natural gas and NGL gathering pipelines with a current capacity of up to approximately 450 mmcf, including an aggregate compression capacity of approximately 310 mmcf. In 2020, compression capacity was increased by approximately 70 mmcf by expanding two existing compressor stations and restarting two additional legacy compression facilities. The system also includes the Hawkeye Gas Facility, which contributes approximately 50 mmcf of the system’s current compression capacity.
- **Crude Oil Gathering:** A crude oil gathering system located primarily in McKenzie, Williams and Mountrail Counties, North Dakota, connecting Hess and third-party owned or operated wells to the Ramberg Terminal Facility, the Tioga Rail Terminal

and the Johnson's Corner Header System. The crude oil gathering system consists of approximately 550 miles of crude oil gathering pipelines with a current capacity of up to approximately 240,000 bopd. The system also includes the Hawkeye Oil Facility, which contributes approximately 75,000 bopd of the system's current capacity.

- *Tioga Gas Plant*: A natural gas processing and fractionation plant located in Tioga, North Dakota, with a current processing capacity of approximately 250 mmcf and fractionation capacity of approximately 60,000 boepd. In 2019, Hess Midstream LP announced plans to expand processing capacity at the plant by 150 mmcf for total processing capacity of 400 mmcf. In 2020, the facility construction was completed for the expansion. Incremental gas processing capacity is expected to be available in 2021 upon completion of a scheduled plant maintenance turnaround, during which the expansion and residue and NGL takeaway pipelines will be tied in. The plant maintenance turnaround was originally planned to occur in the third quarter of 2020 but was deferred to 2021 to ensure safe execution in light of the COVID-19 pandemic.
- *Little Missouri 4*: A natural gas processing plant in McKenzie County, North Dakota, with processing capacity of approximately 200 mmcf, which was placed in service during 2019 and is operated by Targa Resources Corp. Hess Midstream LP owns a 50% interest in Little Missouri 4 through a joint venture with Targa Resources Corp. and is entitled to half of the plant's processing capacity.
- *Mentor Storage Terminal*: A propane storage cavern and rail and truck loading and unloading facility located in Mentor, Minnesota, with approximately 330,000 boe of working storage capacity.
- *Ramberg Terminal Facility*: A crude oil pipeline and truck receipt terminal located in Williams County, North Dakota with a delivery capacity of up to approximately 285,000 bopd of crude oil into an interconnecting pipeline for transportation to the Tioga Rail Terminal and to multiple third-party pipelines and storage facilities.
- *Tioga Rail Terminal*: A 140,000 bopd crude oil and 30,000 boepd NGL rail loading terminal in Tioga, North Dakota that is connected to the Tioga Gas Plant, the Ramberg Terminal Facility and our crude oil gathering system.
- *Crude Oil Rail Cars*: A total of 550 crude oil rail cars, which are operated as unit trains consisting of approximately 100 to 110 crude oil rail cars. These crude oil rail cars have been constructed to DOT-117 standards.
- *Johnson's Corner Header System*: A crude oil pipeline header system located in McKenzie County, North Dakota that receives crude oil by pipeline from Hess and third parties and delivers crude oil to third-party interstate pipeline systems. The facility has a delivery capacity of approximately 100,000 bopd of crude oil.
- *Produced Water Gathering and Disposal*: A produced water gathering system located primarily in Williams and Mountrail Counties, North Dakota, that transports produced water from the wellsite by approximately 270 miles of pipeline in gathering systems or by third-party trucking to water handling facilities for disposal. As of December 31, 2020, five water handling and disposal facilities with a combined capacity of 70,000 barrels per day were in service. These water handling and disposal facilities are owned and operated by Hess Water Services Holdings LLC, an indirect wholly owned subsidiary of Hess Midstream LP. Produced water is also transported to twelve water handling and disposal facilities operated by third parties that have a combined permitted disposal capacity of approximately 170,000 barrels per day.

Hess Midstream has multiple long-term, fee-based commercial agreements effective January 1, 2014 with certain subsidiaries of Hess for gas gathering, crude oil gathering, gas processing and fractionation, storage services, and terminal and export services, each generally with an initial ten-year term that can be extended for an additional ten-year term at the unilateral right of Hess Midstream. These contracts have minimum volumes that the Hess subsidiaries are obligated to provide each calendar quarter. The minimum volume commitments are subject to fluctuation based on nominations covering substantially all of our E&P segment's production and projected third-party volumes that will be purchased in the Bakken. On December 30, 2020, Hess Midstream exercised its renewal options to extend the terms of certain gas gathering, crude oil gathering, gas processing and fractionation, storage, and terminal and export commercial agreements for the secondary term through December 31, 2033. There were no changes to any provisions of the existing commercial agreements as a result of the exercise of the renewal options. Hess Midstream also has long-term, fee based commercial agreements for water handling services effective January 1, 2019 with a subsidiary of Hess, with an initial 14 year term that can be extended for an additional ten-year term at the unilateral right of Hess Midstream. Water handling services are provided for an agreed-upon fee per barrel or the reimbursement of third-party fees.

Competition and Market Conditions

See *Item 1A. Risk Factors* for a discussion of competition and market conditions.

Emergency Preparedness and Response Plans and Procedures

We have in place a series of business and asset-specific emergency preparedness, response and business continuity plans that detail procedures for rapid and effective emergency response and environmental mitigation activities. These plans are maintained,

reviewed and updated as necessary to confirm their accuracy and suitability. Where applicable, they are also reviewed and approved by the relevant host government authorities.

Responder training and drills are routinely held worldwide to assess and continually improve the effectiveness of our plans. Our contractors, service providers, representatives from government agencies and, where applicable, joint venture partners participate in the drills to help ensure that emergency procedures are comprehensive and can be effectively implemented.

To complement internal capabilities and to help ensure coverage for our global operations, we maintain membership contracts with a network of local, regional and global oil spill response and emergency response organizations. At the regional and global level, these organizations include CGA, MSRC, MWCC, WWC and OSRL. CGA and MSRC are domestic spill response organizations and MWCC provides the equipment and personnel to contain underwater well control incidents in the Gulf of Mexico. WWC provides firefighting, well control and engineering services globally. OSRL is a global response organization and is available, when needed, to assist us with any of our assets. In addition to owning response assets in their own right, the organization maintains business relationships that provide immediate access to additional critical response support services if required. OSRL's response assets include nearly 300 recovery and storage vessels and barges, more than 250 skimmers, over 600,000 feet of boom, nine capping stacks and significant quantities of dispersants and other ancillary equipment, including aircraft. In addition to external well control and oil spill response support, we have contracts with wildlife, environmental, meteorology, incident management, medical and security resources. If we were to engage these organizations to obtain additional critical response support services, we would fund such services and, where appropriate, seek reimbursement under our insurance coverage, as described below. In certain circumstances, we pursue and enter into mutual aid agreements with other companies and government cooperatives to receive and provide oil spill response equipment and personnel support. We maintain close associations with emergency response organizations through our representation on the Executive Committees of CGA and MSRC, as well as the Board of Directors of OSRL.

We continue to participate in several industry-wide task forces that are studying better ways to assess the risk of and prevent onshore and offshore incidents, access and control blowouts in subsea environments, and improve containment and recovery methods. The task forces are working closely with the oil and gas industry and international government agencies to implement improvements and increase the effectiveness of oil spill prevention, preparedness, response and recovery processes.

Insurance Coverage and Indemnification

We maintain insurance coverage that includes coverage for physical damage to our property, third-party liability, workers' compensation and employers' liability, general liability, sudden and accidental pollution and other coverage. This insurance coverage is subject to deductibles, exclusions and limitations and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages.

The amount of insurance covering physical damage to our property and liability related to negative environmental effects resulting from a sudden and accidental pollution event, excluding Atlantic Named Windstorm coverage for which we are self-insured, varies by asset, based on the asset's estimated replacement value or the estimated maximum loss. In the case of a catastrophic event, first party coverage consists of two tiers of insurance. The first \$400 million of coverage is provided through an industry mutual insurance group. Above this \$400 million threshold, insurance is carried which ranges in value up to \$1.27 billion in total, depending on the asset coverage level, as described above. The insurance programs covering physical damage to our property exclude business interruption protection for our E&P operations. Additionally, we carry insurance that provides third-party coverage for general liability, and sudden and accidental pollution, up to \$850 million, which coverage under a standard joint operating arrangement would be reduced to our participating interest. Our insurance policies renew at various dates each year. Future insurance coverage could increase in cost and may include higher deductibles or retentions, or additional exclusions or limitations. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are deemed economically acceptable.

Generally, our drilling contracts (and most of our other offshore services contracts) provide for a mutual hold harmless indemnity structure whereby each party to the contract (the Corporation and Contractor) indemnifies the other party for injuries or damages to their personnel and property (and, often, those of its contractors/subcontractors) regardless of fault. Variations may include indemnity exclusions to the extent a claim is attributable to the gross negligence and/or willful misconduct of a party. Third-party claims, on the other hand, are generally allocated on a fault basis.

We are customarily responsible for, and indemnify the Contractor against, all claims including those from third parties, to the extent attributable to pollution or contamination by substances originating from our reservoirs or other property and the Contractor is responsible for and indemnifies us for all claims attributable to pollution emanating from the Contractor's property. Variations may include indemnity exclusions to the extent a claim is attributable to the gross negligence and/or willful misconduct of a party. Additionally, we are generally liable for all of our own losses and most third-party claims associated with catastrophic losses such as damage to reservoirs, blowouts, cratering and loss of hole, regardless of cause, although exceptions for losses attributable to gross negligence and/or willful misconduct do exist. Lastly, some offshore services contracts include overall limitations of the Contractor's liability equal to a fixed negotiated amount. Variations may include exclusions of all contractual indemnities from the liability cap.

Under a standard JOA, each party is liable for all claims arising under the JOA, to the extent of its participating interest (operator or non-operator). Variations include indemnity exclusions when the claim is based upon the gross negligence and/or willful misconduct of the operator, in which case the operator is solely liable. The parties to the JOA may continue to be jointly and severally liable for claims made by third parties in some jurisdictions. Further, under some production sharing contracts between a governmental entity and commercial parties, liability of the commercial parties to the government entity is joint and several.

Government Regulations

The crude oil and natural gas industry is regulated at federal, state, local and foreign government levels. Regulations affecting elements of the energy sector are under continuous review for amendment or expansion over time, which may result in incremental costs of doing business and affect our profitability. See *Regulatory, Legal and Environmental Risks* in *Item 1A. Risk Factors*. Compliance with various existing environmental, health and safety regulations is not expected to have a material adverse effect on our financial condition or results of operations. However, increasingly stringent environmental regulations have resulted and will likely continue to result in higher capital expenditures and operating expenses for us and the oil and gas industry in general and may reduce demand for our products. We spent approximately \$15 million in 2020 for environmental remediation. The level of other expenditures to comply with federal, state, local and foreign country regulations is difficult to quantify as such costs are captured as mostly indistinguishable components of our capital expenditures and operating expenses. For further discussion of environmental, health and safety regulations affecting our business, see *Environment, Health and Safety* in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations*.

Human Capital Management

Corporate Culture and Overview

Our human capital strategy aims to attract and retain our talent by investing in their professional development and providing them with challenging and rewarding opportunities for personal growth. Our workplace culture is guided by our Corporation's values and reinforced by developing quality leadership, fostering diversity and inclusion, emphasizing continuous learning, creating opportunities for engagement, driving innovation and embracing Lean processes. We are pursuing a Life at Hess initiative to optimize the work experience for our multigenerational workforce and unlock the discretionary effort that is required to perform at a high level on a sustained basis. The Life at Hess framework encompasses programs, policies and practices, and a listening system that draws on in-person dialogues, pulse polls and data analytics to help leaders understand employees' issues and perspectives and inform their decision making.

As of December 31, 2020, we had 1,621 employees globally, as detailed below.

	United States	Guyana	Malaysia and JDA	Other (a)	Total
Job Category					
Executives and Senior Officers	31	—	1	—	32
First and Mid-Level Managers	328	—	59	17	404
Professionals	686	—	78	23	787
Other	360	—	2	36	398
Total	1,405	—	140	76	1,621

(a) Other includes our interests in Denmark and Libya.

COVID-19 Response

We prioritize the safety of our workforce. Our safety programs and practices are designed to help ensure that everyone, everywhere gets home safe every day. Our response to COVID-19 reflects this commitment. A multidisciplinary Hess emergency response team has been overseeing plans and precautions to reduce the risks of COVID-19 in the work environment while maintaining business continuity based on the most current recommendations by government and public health agencies. The Corporation has implemented a variety of health and safety measures including enhanced cleaning procedures and modified work practices such as travel restrictions, health screenings, reduced personnel at offshore platforms and onshore work sites wherever this can be done safely, and remote working arrangements for office workers. We continue to adapt our work policies and benefits to prioritize emotional, mental and physical health and well-being. We are taking a deliberate and measured approach to returning to the physical work environment in each of our office locations.

During 2020, we adapted our Life at Hess initiative for a work experience that was largely away from the office and with stringent health and safety protocols throughout our operations, including:

- activated emergency response teams representing all Hess work locations to coordinate effective local deployment of our COVID-19 protocols;

- introduced policies reinforcing that COVID-19 will not negatively impact pay and benefits for employees who may miss work due to COVID-19 exposure, quarantine or test positive;
- provided work from home guidance, technology and training to allow office-based employees to complete their tasks effectively while working remotely;
- modified work schedules for field operations to lessen virus exposure and to accommodate quarantine protocols; and
- offered supplemental medical resources, such as at-home COVID-19 testing kits, mental wellness programs and access to third-party medical experts, at no cost to employees.

Inclusion, Diversity and Equity

In keeping with our values and purpose, we have a longstanding commitment to inclusion and diversity. Our Corporation is committed to providing a global workplace free from discrimination and harassment, where everyone can achieve their full potential. We provide equal employment opportunities for all employees and job candidates regardless of race, color, religion, gender, age, sexual orientation, gender identity, creed, national origin, genetic information, disability, veteran status or any other protected status. Hess' Inclusion, Diversity and Equity Council provides executive leadership and guidance in our hiring, work environment and development activities. Our expectations for an inclusive and diverse workplace and our culture of mutual respect and trust are spelled out in our Code of Conduct and Ethics and related policies and reinforced regularly with employees at every level of our Corporation through training. Additional information regarding our policies and practices, including training and employee engagement initiatives, is included in our annual Sustainability Report, which is available on our website at www.hess.com.

During 2020, Hess maintained or improved diversity among our first and mid-level managers and professionals. Employee turnover, diversity, inclusion and equity, and leadership development metrics, along with qualitative data, are shared with our Board of Directors annually, with more detailed reviews by the Compensation and Management Development Committee throughout the year.

Job Category	Women			Minorities (a)		
	(U.S. and International)			(U.S. Based Employees)		
	2020	2019	2018	2020	2019	2018
Executives and Senior Officers	13 %	16 %	16 %	13 %	13 %	10 %
First and Mid-Level Managers	23 %	22 %	21 %	20 %	19 %	18 %
Professionals	32 %	31 %	33 %	27 %	26 %	27 %
Other	17 %	18 %	19 %	16 %	17 %	17 %
Total	26 %	26 %	26 %	22 %	22 %	22 %

(a) As defined by the U.S. Department of Labor.

Reward Programs

Our compensation and benefits programs are focused on attracting and retaining a highly skilled workforce in a rapidly changing industry. We benchmark our compensation programs annually through industry specific surveys and conduct an annual review to identify and address compensation inequities. Our Corporation maintains an annual incentive plan that applies to all employees, including executive officers, that shares the same enterprise performance metrics for all participants. In addition, we provide a comprehensive wellness program that addresses physical wellness and also focuses on the financial, social and emotional well-being of our employees.

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Information about our Executive Officers

The following table presents information as of March 1, 2021 regarding executive officers of the Corporation:

Name	Age	Office Held* and Business Experience	Year Individual Became an Executive Officer
John B. Hess	66	<i>Chief Executive Officer and Director</i> Mr. Hess has been Chief Executive Officer of the Corporation since 1995 and employed by the Corporation since 1977. He has over 40 years of experience in the oil and gas industry.	1983
Gregory P. Hill	59	<i>President and Chief Operating Officer</i> Mr. Hill has been Chief Operating Officer since 2014 and President of the Corporation's worldwide Exploration and Production business since joining the Corporation in January 2009. Prior to joining the Corporation, Mr. Hill spent 25 years at Royal Dutch Shell and its affiliates in a variety of operations, engineering, technical and managerial roles in Asia-	2009

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		Pacific, Europe and the United States.	
Timothy B. Goodell	63	<i>Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer</i> Mr. Goodell has been General Counsel of the Corporation since 2009, Corporate Secretary since 2016, Chief Compliance Officer since 2017 and Executive Vice President since 2020. Prior to joining the Corporation in 2009, he was a partner at the law firm of White & Case, LLP where he spent 25 years.	2009
John P. Rielly	58	<i>Executive Vice President and Chief Financial Officer</i> Mr. Rielly has been Chief Financial Officer of the Corporation since 2004 and Executive Vice President since 2020. Mr. Rielly previously served as Vice President and Controller of the Corporation from 2001 to 2004. Prior to joining the Corporation in 2001, he was a Partner at Ernst & Young, LLP where he was employed for 17 years.	2002
Richard Lynch	63	<i>Senior Vice President, Technology and Services</i> Mr. Lynch has been Senior Vice President, Technology and Services of the Corporation since 2018. Mr. Lynch previously was Senior Vice President Global Developments, Drilling and Completions from 2014. Prior to joining the Corporation in 2014, Mr. Lynch spent over 30 years in well delivery and operations, as well as project and asset management, with BP plc and ARCO.	2018
Gerbert Schoonman	55	<i>Senior Vice President, Global Production</i> Mr. Schoonman has been Senior Vice President, Global Production of the Corporation since January 2020. Since joining the Company in 2011, he served in various operational leadership roles, including as Vice President, Production – Asia Pacific, from January 2011 through August 2012; Vice President, Onshore – Bakken from September 2012 through December 2016; and most recently, as Vice President, Offshore since January 2017. Prior to joining the Corporation, he spent 20 years with Royal Dutch Shell where he served in operational and leadership roles.	2020
Andrew Slentz	59	<i>Senior Vice President, Human Resources and Office Management</i> Mr. Slentz has been Senior Vice President, Human Resources of the Corporation since April 2016 and responsible for Office Management since 2018. Prior to joining the Corporation in 2016, Mr. Slentz served as Executive Vice President of Administration and Human Resources at Peabody Energy since 2010. Mr. Slentz has over 25 years in human resources experience at large international public companies.	2016
Barbara Lowery-Yilmaz	64	<i>Senior Vice President and Chief Exploration Officer</i> Ms. Lowery-Yilmaz has been the Senior Vice President, Exploration of the Corporation since August 2014. Ms. Lowery-Yilmaz has over 30 years of oil and gas industry experience in exploration and technology with BP plc and its affiliates including senior leadership roles.	2014

* All officers referred to herein hold office in accordance with the By-laws until the first meeting of directors in connection with the annual meeting of stockholders of the Registrant and until their successors shall have been duly chosen and qualified. Each of said officers was elected to the office opposite their name on June 2, 2020.

Except for Mr. Slentz, each of the above officers has been employed by the Corporation or its affiliates in various managerial and executive capacities for more than five years. Prior to joining the Corporation, Mr. Slentz served in senior executive positions in human resources at Peabody Energy and its affiliates.

Access to Our Reports

We make available free of charge through our website, www.hess.com, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission. The information on our website is not incorporated by reference in this report. Our Code of Business Conduct and Ethics, Corporate Governance Guidelines, and the charters for the Audit Committee, Compensation and Management Development Committee, Corporate Governance and Nominating Committee and Environmental, Health and Safety Committee of the Board of Directors are available on our website and are also available free of charge upon request to Investor Relations at our principal executive office. We also file with the New York Stock Exchange (NYSE) an annual certification that our Chief Executive Officer is unaware of any violation of the NYSE's corporate governance standards.

Item 1A. Risk Factors

Our business activities and the value of our securities are subject to significant risks, including the risk factors described below. These risk factors could negatively affect our operations, financial condition, liquidity and results of operations, and as a result, holders and purchasers of our securities could lose part or all of their investments. It is possible that additional risks relating to our securities may be described in a prospectus supplement if we issue securities in the future.

Market and Third-Party Risks

Our business and operating results are highly dependent on the market prices of crude oil, NGL and natural gas, which can be very volatile. Our estimated proved reserves, revenue, operating cash flows, operating margins, liquidity, financial condition and future earnings are highly dependent on the benchmark market prices of crude oil, NGL and natural gas, and our associated realized price differentials, which are volatile and influenced by numerous factors beyond our control. The major foreign oil producing countries, including members of OPEC, may exert considerable influence over the supply and price of crude oil and refined petroleum products. Their ability to agree on a common policy on rates of production and other matters may have a significant impact on the oil markets. Other factors include, but are not limited to: worldwide and domestic supplies of and demand for crude oil, NGL and natural gas, political conditions and events (including weather, instability, changes in governments, armed conflict, economic sanctions and outbreaks of infectious diseases, such as COVID-19) around the world and in particular in crude oil or natural gas producing regions, the cost of exploring for, developing and producing crude oil, NGL and natural gas, the price and availability of alternative fuels or other forms of energy, the effect of energy conservation and environmental protection efforts and overall economic conditions globally. The sentiment of commodities trading markets as well as other supply and demand factors, including COVID-19, may also influence the selling prices of crude oil, NGL and natural gas. Average benchmark prices for 2020 were \$39.34 per barrel for WTI (2019: \$57.04; 2018: \$64.90) and \$43.21 per barrel for Brent (2019: \$64.16; 2018: \$71.69). In order to manage the potential volatility of cash flows and credit requirements, we maintain significant bank credit facilities. An inability to access, renew or replace such credit facilities or access other sources of funding as they mature would negatively impact our liquidity. Furthermore, from time to time we have entered into, and may in the future, enter into or modify commodity price hedging arrangements to manage commodity price volatility. These arrangements may limit potential upside from commodity price increases, or expose us to additional risks, such as counterparty credit risk, which could adversely impact our cash flow, liquidity or financial condition.

Our business and operations have been and may continue to be adversely affected by COVID-19 or other similar public health developments and the recent reduced demand for oil and natural gas. COVID-19 and the related actions taken by governments and businesses to manage the pandemic, including voluntary and mandatory quarantines and travel and other restrictions, have resulted in a significant and swift reduction in economic activity. Certain jurisdictions have begun re-opening only to return to restrictions in the face of increases in new COVID-19 cases. As a result of COVID-19, our operations, and those of our business partners, service companies and suppliers, have experienced and may continue to experience further adverse effects, including but not limited to: disruptions, delays or temporary suspensions of operations and supply chains; temporary inaccessibility or closures of facilities; and workforce impacts from illness, school closures and other community response measures. We have implemented a variety of health and safety measures, including enhanced cleaning procedures and modified work practices, such as travel restrictions; health screenings; reduced personnel at offshore platforms and onshore work sites, wherever such reduction can be done safely; and remote working arrangements for office workers. There is no certainty that these or any other future measures will be sufficient to mitigate the risks posed by the disease, including the risk of infection of key employees, and our ability to perform certain functions could be impaired by these new business practices. For example, our reliance on technology has necessarily increased due to our encouragement of remote communications and other work-from-home practices, which could make us more vulnerable to cyber-attacks. To the extent we or our business partners, service companies or suppliers continue to experience restrictions or other effects, our financial condition, results of operations and future expansion projects may be adversely affected.

In addition to the global health concerns of COVID-19, the pandemic has negatively affected the U.S. and global economy and severely adversely impacted demand for oil and natural gas. The prolonged continuation or amplification of the outbreak of COVID-19 could result in further economic downturn that may affect our operating results in the long-term. In addition, the effects of COVID-19 and concerns regarding its global spread have negatively impacted the domestic and international demand for crude oil and natural gas, which has contributed to price volatility and adversely affected the demand for and marketability of crude oil, natural gas and NGL. Containment measures implemented to mitigate the spread of COVID-19 could continue to be widespread and lead to sustained adoption of certain behavioral changes, such as reduced travel and work-from-home policies, which could result in further reductions in demand for and consumption of energy commodities. The reduction in consumer demand for crude oil, natural gas and NGL has created a supply imbalance, which could require further curtailments and shut-ins of production by the industry and further increase the costs of commercial storage and midstream contracts.

The timeline and potential magnitude of COVID-19 remains unknown and will depend on future developments, including, among others, the availability of vaccines and effective treatments and the extent to which normal economic and operating conditions resume. In the event one or more of our business partners is adversely affected by COVID-19 or the current market environment, that may impact our costs and ability to conduct business with them. In addition, we may face an increased risk of changes in the regulation related to our business resulting from COVID-19, such as the imposition of limitations on our workforce's ability to access our facilities. We also are subject to litigation risk and possible loss contingencies related to COVID-19, including with respect to

commercial contracts, employee matters and insurance arrangements. We may face additional asset impairments, decreases in proved reserves, along with other accounting charges as demand for crude oil, natural gas and NGL decreases. The current environment may make it more difficult to

comply with covenants and other restrictions in agreements governing our debt, and a lack of confidence in our industry on the part of the financial markets may result in a lack of access to capital, any of which could lead to reduced liquidity.

As the impact from COVID-19 remains difficult to predict, the extent to which it may negatively affect our operating results is uncertain. Any impact will depend on future developments and new information that may emerge regarding the severity and duration of COVID-19 and the actions taken by authorities to contain it or treat its impact, all of which are beyond our control.

We do not always control decisions made under joint operating agreements and the parties under such agreements may fail to meet their obligations. We conduct many of our E&P operations through joint operating agreements with other parties under which we may not control decisions, either because we do not have a controlling interest or are not operator under the agreement. There is risk that these parties may at any time have economic, business, or legal interests or goals that are inconsistent with ours, and therefore decisions may be made which are not what we believe is in our best interest. Moreover, parties to these agreements may be unable to meet their economic or other obligations and we may be required to fulfill those obligations alone. In either case, the value of our investment may be adversely affected.

Our industry is highly competitive and many of our competitors are larger and have greater resources and more diverse portfolios than we have. The petroleum industry is highly competitive and very capital intensive. We encounter competition from numerous companies, including acquiring rights to explore for crude oil and natural gas. To a lesser extent, we are also in competition with producers of alternative fuels or other forms of energy, including wind, solar and electric power, and in the future, could face increasing competition due to the development and adoption of new technologies. Many competitors, including national oil companies, are larger and have substantially greater resources to acquire and develop oil and gas assets. In addition, competition for drilling services, technical expertise and equipment may affect the availability of technical personnel and drilling rigs, resulting in increased capital and operating costs. Many of our competitors have a more diverse portfolio of assets, which may minimize the impact of adverse events occurring at any one location.

Operational and Strategic Risks

If we fail to successfully increase our reserves, our future crude oil and natural gas production will be adversely impacted. We own or have access to a finite amount of oil and gas reserves, which will be depleted over time. Replacement of oil and gas production and reserves, including proved undeveloped reserves, is subject to successful exploration drilling, development activities, and enhanced recovery programs. Therefore, future oil and gas production is dependent on technical success in finding and developing additional hydrocarbon reserves. Exploration activity involves the interpretation of seismic and other geological and geophysical data, which does not always successfully predict the presence of commercial quantities of hydrocarbons. Drilling risks include unexpected adverse conditions, irregularities in pressure or formations, equipment failure, blowouts and weather interruptions. Future developments may be affected by unforeseen reservoir conditions, which negatively affect recovery factors or flow rates. Similar risks may be encountered in the production of oil and gas on properties acquired from others. In addition, replacing reserves and developing future production are also influenced by the price of crude oil and natural gas and costs of drilling and development activities. Lower crude oil and natural gas prices may reduce capital available for our exploration and development activities, render certain development projects uneconomic or delay their completion, and result in negative revisions to existing reserves while increasing drilling and development costs could negatively affect expected economic returns.

There are inherent uncertainties in estimating quantities of proved reserves and discounted future net cash flows, and actual quantities may be lower than estimated. Numerous uncertainties exist in estimating quantities of proved reserves and future net revenues from those reserves. Actual future production, oil and gas prices, revenues, taxes, capital expenditures, operating expenses, and quantities of recoverable oil and gas reserves may vary substantially from those assumed in the estimates and could materially affect the estimated quantities of our proved reserves and the related future net revenues. In addition, reserve estimates may be subject to downward or upward changes based on production performance, purchases or sales of properties, results of future development, prevailing oil and gas prices, production sharing contracts, which may decrease reserves as crude oil and natural gas prices increase, and other factors. Crude oil prices declined in 2020 and 2019, relative to comparative periods, resulting in reductions to our reported proved reserves. If crude oil prices in 2021 average below prices used to determine proved reserves at December 31, 2020, it could have an adverse effect on our estimates of proved reserve volumes and on the value of our business. See *Crude Oil and Natural Gas Reserves in Critical Accounting Policies and Estimates* in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations*.

Catastrophic and other events, whether naturally occurring or man-made, may materially affect our operations and financial condition. Our oil and gas operations are subject to numerous risks and hazards inherent to operating in the crude oil and natural gas industry, including catastrophic events, which may damage or destroy assets, interrupt operations, result in personal injury and have other significant adverse effects. These events include unexpected drilling conditions, pressure conditions or irregularities in reservoir formations, equipment malfunctions or failures, derailments, fires, explosions, blowouts, cratering, pipeline interruptions and ruptures, hurricanes, severe weather, geological events, shortages in availability of skilled labor, cyber-attacks or health measures related to COVID-19. We maintain insurance coverage against many, but not all, potential losses and liabilities in amounts we deem

prudent, including for property and casualty losses. There can be no assurance that such insurance will adequately protect us against liability from all potential consequences and damages. Moreover, some forms of insurance may be unavailable in the future or be available only on terms that are deemed economically unacceptable.

Significant time delays between the estimated and actual occurrence of critical events associated with development projects may result in

material negative economic consequences. As part of our business, we are involved in large development projects, the completion of which may be delayed beyond what was originally planned. Such examples include, but are not limited to, delays in receiving necessary approvals from project members or regulatory or other government agencies, timely access to necessary equipment, availability of necessary personnel, construction delays, unfavorable weather conditions, equipment failures, and outbreaks of infectious diseases, such as COVID-19. These delays could impact our future results of operations and cash flows.

An inability to secure personnel, drilling rigs, equipment, supplies and other required services or to retain key employees may result in material negative economic consequences. We are dependent on oilfield service companies for items including drilling rigs, equipment, supplies and skilled labor. The availability and cost of drilling rigs, equipment, supplies and skilled labor will fluctuate over time given the cyclical nature of the E&P industry. As a result, we may encounter difficulties in obtaining required services or could face an increase in cost, including as a result of changes to our industry due to COVID-19, which may impact our ability to run our operations and deliver projects on time with the potential for material negative economic consequences. In addition, difficulty in recruiting and retaining adequate numbers of experienced technical personnel could negatively impact our ability to deliver on our strategic goals. Our future success also depends upon the continued service of key members of our senior management team, who play an important role in developing and implementing our strategy. An inability to recruit and retain adequate numbers of experienced technical and professional personnel in the necessary locations or the loss or departure of key members of senior management may prevent us from executing our strategy in full or, in part, which could negatively impact our business.

Disruption, failure or cyber security breaches affecting or targeting computer, telecommunications systems, and infrastructure used by the Corporation or our business partners may materially impact our business and operations. Computers and telecommunication systems are an integral part of our exploration, development and production activities and the activities of our business partners. We use these systems to analyze and store financial and operating data and to communicate within our corporation and with outside business partners. Our reliance on technology has increased due to the increased use of remote communications and other work-from-home practices in response to COVID-19. Technical system flaws, power loss, cyber security risks, including cyber or phishing-attacks, unauthorized access, malicious software, data privacy breaches by employees or others with authorized access, ransomware, and other cyber security issues could compromise our computer and telecommunications systems or those of our business partners and result in disruptions to our business operations or the access, disclosure or loss of our data and proprietary information. In addition, computers control oil and gas production, processing equipment, and distribution systems globally and are necessary to deliver our production to market. A disruption, failure or a cyber breach of these operating systems, or of the networks and infrastructure on which they rely, could damage critical production, distribution and/or storage assets, delay or prevent delivery to markets, and make it difficult or impossible to accurately account for production and settle transactions. As a result, any such disruption, failure or cyber breach and any resulting investigation or remediation costs, litigation or regulatory action could have a material adverse impact on our cash flows and results of operations, reputation and competitiveness. We routinely experience attempts by external parties to penetrate and attack our networks and systems. Although such attempts to date have not resulted in any material breaches, disruptions, financial loss, or loss of business-critical information, our systems and procedures for protecting against such attacks and mitigating such risks may prove to be insufficient in the future and such attacks could have an adverse impact on our business and operations, including damage to our reputation and competitiveness, remediation costs, litigation or regulatory actions. In addition, as technologies evolve and these cyber security attacks become more sophisticated, we may incur significant costs to upgrade or enhance our security measures to protect against such attacks and we may face difficulties in fully anticipating or implementing adequate preventive measures or mitigating potential harm.

Financial Risks

We have substantial capital requirements, and we may not be able to obtain needed financing on satisfactory terms. The exploration, development and production of crude oil and natural gas involve substantial costs, which may not be fully funded from operations. Two of the three major credit rating agencies that rate our debt have assigned an investment grade rating. Although currently we do not have any borrowings under our long-term credit facility, a ratings downgrade, continued weakness in the oil and gas industry or negative outcomes within commodity and financial markets could adversely impact our access to capital markets by increasing the costs of financing, or by impacting our ability to obtain financing on satisfactory terms. In addition, a ratings downgrade may require that we issue letters of credit or provide other forms of collateral under certain contractual requirements. Environmental concerns and other factors have led to lower oil and gas representation in certain key equity market indices and may increase our costs to access the equity capital markets. Any inability to access capital markets could adversely impact our financial adaptability and our ability to execute our strategy.

We engage in risk management transactions designed to mitigate commodity price volatility and other risks that may impede our ability to benefit from commodity price increases and can expose us to similar potential counterparty credit risk as amounts due from the sale of hydrocarbons. We may enter into commodity price hedging arrangements to protect us from commodity price declines. These arrangements may, depending on the instruments used and the level of additional hedges involved, limit any potential upside from commodity price increases. As with accounts receivable from the sale of hydrocarbons, we may be exposed to potential economic loss should a counterparty be unable or unwilling to perform their obligations under the terms of a hedging agreement. In addition, we are exposed to risks related to changes in interest rates and foreign currency values, and may engage in hedging activities to mitigate related volatility.

The alteration or discontinuation of LIBOR may adversely affect our borrowing costs. Certain borrowings on our credit facilities and term loan

may use LIBOR as a benchmark for establishing the rate. LIBOR is the subject of recent national, international and other regulatory guidance and proposals for reform. These reforms and other pressures may cause LIBOR to be discontinued after 2021 or to perform differently than in the past. In the U.S., the Alternative Reference Rates Committee, which was convened by the Federal Reserve Board and the Federal Reserve Bank of New York, has proposed SOFR as an alternative to LIBOR. At this time, the consequences of these developments cannot be entirely predicted, but could include fluctuations in interest rates or an increase in the cost of our credit facility borrowings.

Regulatory, Legal and Environmental Risks

Our oil and gas operations are subject to environmental risks and environmental, health and safety laws and regulations that can result in significant costs and liabilities. Our oil and gas operations are subject to environmental risks such as oil spills, produced water spills, gas leaks and ruptures and discharges of substances or gases that could expose us to substantial liability for pollution or other environmental damage. Our operations are also subject to numerous U.S. federal, state, local and foreign environmental, health and safety laws and regulations. Non-compliance with these laws and regulations may subject us to administrative, civil or criminal penalties, remedial clean-ups, natural resource damages and other liabilities. In addition, increasingly stringent environmental regulations have resulted and will likely continue to result in higher capital expenditures and operating expenses for us. Similarly, we have material legal obligations to dismantle, remove and abandon production facilities and wells that will occur many years in the future, in most cases. These estimates may be impacted by future changes in regulations, solvency of subsequent owners and partners and other uncertainties.

Concerns have been raised in certain jurisdictions where we have operations concerning the safety and environmental impact of the drilling and development of shale oil and gas resources, particularly hydraulic fracturing, water usage, flaring of associated natural gas and air emissions. While we believe that these operations can be conducted safely and with minimal impact on the environment, regulatory bodies are responding to these concerns and may impose moratoriums and new regulations on such drilling operations that would likely have the effect of prohibiting or delaying such operations and increasing their cost.

Climate change and sustainability initiatives may result in significant operational changes and expenditures, reduced demand for our products and adversely affect our business. We recognize that climate change and sustainability is a growing global environmental concern. Continuing political and social attention to the issue of climate change and sustainability has resulted in both existing and pending international agreements and national, regional or local legislation and regulatory measures to limit GHG emissions. These agreements and measures may require, or could result in future legislation and regulatory measures that require, significant equipment modifications, operational changes, taxes, or purchase of emission credits to reduce emission of GHGs from our operations, which may result in substantial capital expenditures and compliance, operating, maintenance and remediation costs. In addition, our production is sold to third parties that produce petroleum fuels, which through normal end user consumption result in the emission of GHGs. As a result of heightened public awareness and attention to climate change and sustainability as well as continued regulatory initiatives to reduce the use of these fuels, demand for crude oil and other hydrocarbons may be reduced, which may have an adverse effect on our sales volumes, revenues and margins. The imposition and enforcement of stringent GHG emissions reduction requirements could severely and adversely impact the oil and gas industry and therefore significantly reduce the value of our business. Shareholder activism has been recently increasing in our industry, and shareholders may attempt to effect changes to our business or governance, whether by shareholder proposals, public campaigns, proxy solicitations or otherwise. In addition, certain financial institutions, institutional investors and other sources of capital have begun to limit or eliminate their investment in oil and gas activities due to concerns about climate change, which could make it more difficult to finance our business. Furthermore, increasing attention to climate change risks and sustainability has resulted in governmental investigations, and public and private litigation, which could increase our costs or otherwise adversely affect our business. For example, beginning in 2017, certain states, municipalities and private associations in California, Delaware, Maryland, Rhode Island and South Carolina separately filed lawsuits against oil, gas and coal producers, including us, for alleged damages purportedly caused by climate change. Such actions could adversely impact our business by distracting management and other personnel from their primary responsibilities, require us to incur increased costs, and/or result in reputational harm.

We are subject to changing laws and regulations and other governmental actions that can significantly and adversely affect our business. Political or regulatory developments and governmental actions, including federal, state, local, territorial and foreign laws and regulations may adversely affect our operations and those of our counterparties with whom we have contracted, which may affect our financial results. These requirements relate to tax increases and retroactive tax claims, disallowance of tax credits and

deductions, including post-production deductions from royalty payments; limitations or prohibitions on the sales of new and extensions on existing oil and gas leases; expropriation or nationalization of property; mandatory government participation, cancellation or amendment of contract rights; imposition of capital controls or blocking of funds; changes in import and export regulations; the imposition of tariffs; and anti-bribery or anti-corruption laws. In recent years, proposals for limitations on access to oil and gas exploration and development opportunities and related litigation have grown in certain areas and may include efforts to reduce access to public and private lands; restriction of exploration and production activities within government-owned and other lands; delaying or canceling permits for drilling or pipeline construction; restrictions or changes to existing pipeline easements; limiting or banning industry techniques such as hydraulic fracturing and/or adding restrictions on the use of water and associated disposal; imposition of set-backs on oil and gas sites; reduction of sulfur content in bunker fuel; delaying or denying air-quality or siting permits; advocating for increased regulations, punitive taxation, or citizen ballot initiatives or moratoriums on industry activity; and the use of social media channels to cause reputational harm. Costs associated with responding to these anti-development efforts or complying with any new legal or regulatory requirements could significantly and adversely affect our business, financial condition and results of operations. For example, if a temporary or permanent shutdown of the DAPL occurs as a result of the on-going litigation related to use of its easement to cross

under the Missouri River, we will need to use alternative means to transport approximately 55,000 bopd of crude oil production in the Bakken, which may increase Bakken price differentials because it would require the use of additional rail cars and personnel to move any displaced DAPL barrels.

Political instability in areas where we operate can adversely affect our business. Some of the international areas in which we operate are politically less stable than other areas and may be subject to civil unrest, conflict, insurgency, corruption, security risks and labor unrest. Political instability and civil unrest in North Africa, South America and the Middle East has affected and may continue to affect our interests in these areas as well as oil and gas markets generally. In addition, geographic territorial border disputes may affect our business in certain areas, such as the border dispute between Guyana and Venezuela over a portion of the Stabroek Block. Political instability exposes our operations to increased risks, including increased difficulty in obtaining required permits and government approvals, enforcing our agreements in those jurisdictions and potential adverse actions by local government authorities. The threat of terrorism around the world also poses additional risks to our operations and the operations of the oil and gas industry in general.

One of our subsidiaries is the general partner of a publicly traded limited partnership, Hess Midstream LP. The responsibilities associated with being a general partner expose us to a broader range of legal liabilities. Our control of Hess Midstream LP bestows upon us additional duties and obligations including, but not limited to, the obligations associated with managing potential conflicts of interests and additional reporting requirements from the Securities and Exchange Commission. These heightened duties expose us to additional potential for legal claims that may have a material negative economic impact on our shareholders. Moreover, these increased duties may lead to an increase in compliance costs.

Item 1B. Unresolved Staff Comments

None.

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Item 3. Legal Proceedings

We are subject to loss contingencies with respect to various claims, lawsuits and other proceedings. A liability is recognized in our consolidated financial statements when it is probable that a loss has been incurred and the amount can be reasonably estimated. If the risk of loss is probable, but the amount cannot be reasonably estimated or the risk of loss is only reasonably possible, a liability is not accrued; however, we disclose the nature of those contingencies. We cannot predict with certainty if, how or when existing claims, lawsuits and proceedings will be resolved or what the eventual relief, if any, may be, particularly for proceedings that are in their early stages of development or where plaintiffs seek indeterminate damages.

We, along with many companies that have been or continue to be engaged in refining and marketing of gasoline, have been a party to lawsuits and claims related to the use of MTBE in gasoline. A series of similar lawsuits, many involving water utilities or governmental entities, were filed in jurisdictions across the U.S. against producers of MTBE and petroleum refiners who produced gasoline containing MTBE, including us. The principal allegation in all cases was that gasoline containing MTBE was a defective product and that these producers and refiners are strictly liable in proportion to their share of the gasoline market for damage to groundwater resources and are required to take remedial action to ameliorate the alleged effects on the environment of releases of MTBE. The majority of the cases asserted against us have been settled. There are three remaining active cases, filed by Pennsylvania, Rhode Island, and Maryland. In June 2014, the Commonwealth of Pennsylvania filed a lawsuit alleging that we and all major oil companies with operations in Pennsylvania, have damaged the groundwater by introducing thereto gasoline with MTBE. The Pennsylvania suit has been forwarded to the existing MTBE multidistrict litigation pending in the Southern District of New York. In September 2016, the State of Rhode Island also filed a lawsuit alleging that we and other major oil companies damaged the groundwater in Rhode Island by introducing thereto gasoline with MTBE. The suit filed in Rhode Island is proceeding in federal court. In December 2017, the State of Maryland filed a lawsuit alleging that we and other major oil companies damaged the groundwater in Maryland by introducing thereto gasoline with MTBE. The suit, filed in Maryland state court, was served on us in January 2018 and has been removed to federal court by the defendants.

In September 2003, we received a directive from the New Jersey Department of Environmental Protection (NJDEP) to remediate contamination in the sediments of the Lower Passaic River. The NJDEP is also seeking natural resource damages. The directive, insofar as it affects us, relates to alleged releases from a petroleum bulk storage terminal in Newark, New Jersey we previously owned. We and over 70 companies entered into an Administrative Order on Consent with the EPA to study the same contamination; this work remains ongoing. We and other parties settled a cost recovery claim by the State of New Jersey and agreed with the EPA to fund remediation of a portion of the site. On March 4, 2016, the EPA issued a Record of Decision (ROD) in respect of the lower eight miles of the Lower Passaic River, selecting a remedy that includes bank-to-bank dredging at an estimated cost of \$1.38 billion. The ROD does not address the upper nine miles of the Lower Passaic River or the Newark Bay, which may require additional remedial action. In addition, the federal trustees for natural resources have begun a separate assessment of damages to natural resources in the Passaic River. Given that the EPA has not selected a remedy for the entirety of the Lower Passaic River or the Newark Bay, total remedial costs cannot be reliably estimated at this time. Based on currently known facts and circumstances, we do not believe that this matter will result in a significant liability to us because our former terminal did not store or use contaminants which are of concern in the river sediments and could not have contributed contamination along the river's length. Further, there are numerous other parties who we expect will bear the cost of remediation and damages.

In March 2014, we received an Administrative Order from the EPA requiring us and 26 other parties to undertake the Remedial Design for the remedy selected by the EPA for the Gowanus Canal Superfund Site in Brooklyn, New York. Our alleged liability derives from our former ownership and operation of a fuel oil terminal and connected shipbuilding and repair facility adjacent to the Canal. The remedy selected by the EPA includes

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dredging of surface sediments and the placement of a cap over the deeper sediments throughout the Canal and in-situ stabilization of certain contaminated sediments that will remain in place below the cap. The EPA's original estimate was that this remedy would cost \$506 million; however, the ultimate costs that will be incurred in connection with the design and implementation of the remedy remain uncertain. We have complied with the EPA's March 2014 Administrative Order and contributed funding for the Remedial Design based on an allocation of costs among the parties determined by a third-party expert. In January 2020, we received an additional Administrative Order from the EPA requiring us and several other parties to begin Remedial Action along the uppermost portion of the Canal. We intend to comply with this Administrative Order. The remediation work began in the fourth quarter of 2020. Based on currently known facts and circumstances, we do not believe that this matter will result in a significant liability to us, and the costs will continue to be allocated amongst the parties, as they were for the Remedial Design.

From time to time, we are involved in other judicial and administrative proceedings relating to environmental matters. We periodically receive notices from the EPA that we are a "potential responsible party" under the Superfund legislation with respect to various waste disposal sites. Under this legislation, all potentially responsible parties may be jointly and severally liable. For any site for which we have received such a notice, the EPA's claims or assertions of liability against us relating to these sites have not been fully developed, or the EPA's claims have been settled or a settlement is under consideration, in all cases for amounts that are not material. Beginning in 2017, certain states, municipalities and private associations in California, Delaware, Maryland, Rhode Island and South Carolina separately filed lawsuits against oil, gas and coal producers, including us, for alleged damages purportedly caused by climate change. These proceedings include claims for monetary damages and injunctive relief. Beginning in 2013, various

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parishes in Louisiana filed suit against approximately 100 oil and gas companies, including us, alleging that the companies' operations and activities in certain fields violated the State and Local Coastal Resource Management Act of 1978, as amended, and caused contamination, subsidence and other environmental damages to land and water bodies located in the coastal zone of Louisiana. The plaintiffs seek, among other things, the payment of the costs necessary to clear, re-vegetate and otherwise restore the allegedly impacted areas. The ultimate impact of the aforementioned proceedings, and of any related proceedings by private parties, on our business or accounts cannot be predicted at this time due to the large number of other potentially responsible parties and the speculative nature of clean-up cost estimates.

We are also involved in other judicial and administrative proceedings from time to time in addition to the matters described above, including claims related to post-production deductions from royalty payments. We cannot predict with certainty if, how or when such proceedings will be resolved or what the eventual relief, if any, may be, particularly for proceedings that are in their early stages of development or where plaintiffs seek indeterminate damages. Numerous issues may need to be resolved, including through potentially lengthy discovery and determination of important factual matters before a loss or range of loss can be reasonably estimated for any proceeding.

Subject to the foregoing, in management's opinion, based upon currently known facts and circumstances, the outcome of lawsuits, claims and proceedings, including the matters disclosed above, is not expected to have a material adverse effect on our financial condition, results of operations or cash flows. However, we could incur judgments, enter into settlements, or revise our opinion regarding the outcome of certain matters, and such developments could have a material adverse effect on our results of operations in the period in which the amounts are accrued and our cash flows in the period in which the amounts are paid.

Item 4. Mine Safety Disclosures

None.

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PART II

Item 5. Market for the Registrant's Common Stock, Related Stockholder Matters and Issuer Purchases of Equity Securities

Stock Market Information, Holders and Dividends

Our common stock is traded principally on the New York Stock Exchange (ticker symbol: HES). At January 31, 2021, there were 2,867 stockholders (based on the number of holders of record) who owned a total of 306,986,553 shares of common stock. In 2020, 2019 and 2018, cash dividends on common stock totaled \$1.00 per share per year (\$0.25 per quarter).

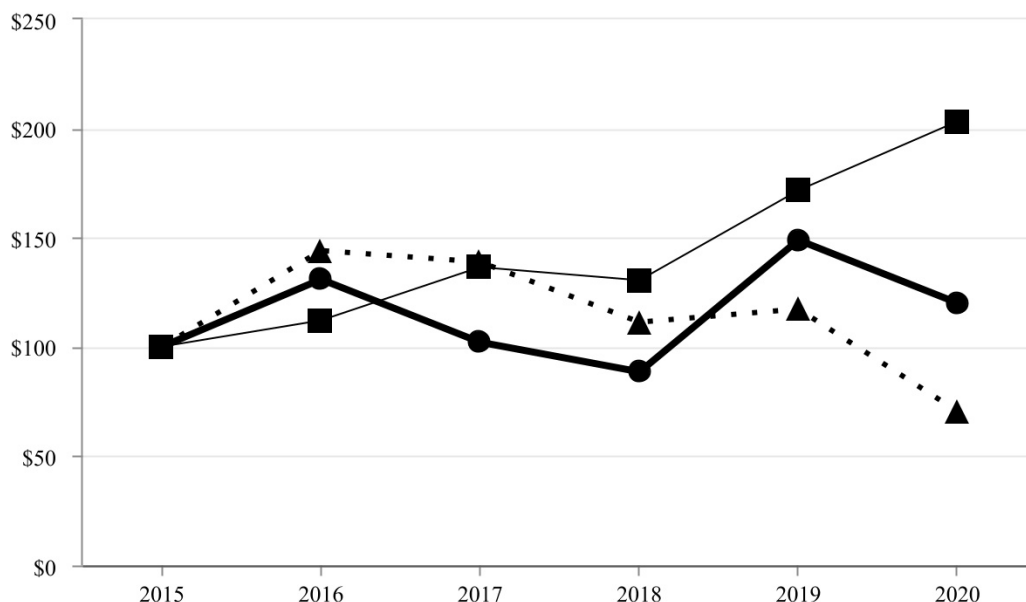
Performance Graph

Set forth below is a line graph comparing the five-year shareholder returns on a \$100 investment in our common stock assuming reinvestment of dividends, against the cumulative total returns for the following:

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- Standard & Poor's (S&P) 500 Stock Index, which includes us.
- Proxy Peer Group comprising 10 oil and gas peer companies, including us, as disclosed in our 2020 Proxy Statement, excluding Chesapeake Energy Corporation, which filed for bankruptcy in June 2020, and Noble Energy, Inc. which was acquired in October 2020.

Comparison of Five-Year Shareholder Returns
Years Ended December 31,



	2015	2016	2017	2018	2019	2020
Hess Corporation	\$100.00	\$130.90	\$102.01	\$88.61	\$148.62	\$120.10
S&P 500	\$100.00	\$111.95	\$136.38	\$130.39	\$171.44	\$202.96
Proxy Peer Group	\$100.00	\$143.91	\$138.85	\$111.28	\$117.20	\$70.48

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Share Repurchase Activities

Our share repurchases for the year ended December 31, 2020, were as follows:

	Total Number of Shares Purchased (a) (b)	Average Price Paid per Share (a)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (c)	Maximum Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs (d) (In millions)
2020				
March 1, 2020 through March 31, 2020	35,202	\$ 32.34	—	\$ 650
Total for 2020	35,202	\$ 32.34	—	

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- (a) Repurchased in open-market transactions. The average price paid per share is inclusive of transaction fees.
- (b) All of the shares repurchased were subsequently granted to directors in accordance with the Non-Employee Directors' Stock Award Program.
- (c) Since initiation of the buyback program in August 2013, total shares repurchased through December 31, 2020 amounted to 91.9 million at a total cost of \$6.85 billion including transaction fees.
- (d) In March 2013, we announced that our Board of Directors approved a stock repurchase program that authorized the purchase of common stock up to a value of \$4.0 billion. In May 2014, the share repurchase program was increased to \$6.5 billion and in March 2018, it was increased further to \$7.5 billion.

Equity Compensation Plans

Following is information related to our equity compensation plans at December 31, 2020.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights *	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column*)	
			(a)	(b)
Equity compensation plans approved by security holders	4,382,243	\$ 61.57	13,006,658	(b)
Equity compensation plans not approved by security holders (c)	—	—	—	—

(a) This amount includes 4,382,243 shares of common stock issuable upon exercise of outstanding stock options. This amount excludes 806,270 performance share units (PSUs) for which the number of shares of common stock to be issued may range from 0% to 200%, based on our total shareholder return (TSR) relative to the TSR of a predetermined group of peer companies over a three-year performance period ending December 31 of the year prior to settlement of the grant. Beginning with the PSUs granted in 2020, the Corporation's TSR is compared to the TSR of a predetermined group of peer companies and the S&P 500 index over the three-year performance period. In addition, this amount also excludes 1,917,459 shares of common stock issued as restricted stock pursuant to our equity compensation plans.

(b) These securities may be awarded as stock options, restricted stock, PSUs or other awards permitted under our equity compensation plan.

(c) We have a Non-Employee Director's Stock Award Plan pursuant to which each of our non-employee directors received \$175,000 in value of our common stock. These awards are made from shares we have purchased in the open market.

See Note 14, Share-based Compensation in the Notes to Consolidated Financial Statements for further discussion of our equity compensation plans.

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Item 6. Selected Financial Data

The following is a five-year summary of selected financial data that should be read in conjunction with both our Consolidated Financial Statements and Accompanying Notes, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations included elsewhere in this Annual Report:

	2020	2019	2018	2017	2016
	(In millions, except per share amounts)				
Income Statement Selected Financial Data					
Sales and other operating revenues					
Crude oil (a)	\$ 3,149	\$ 5,233	\$ 4,960	\$ 4,239	\$ 3,639
Natural gas liquids (a)	297	347	533	457	264
Natural gas (a)	648	876	965	750	766
Other operating revenues (b)	573	39	(135)	20	93
Total Sales and other operating revenues	\$ 4,667	\$ 6,495	\$ 6,323	\$ 5,466	\$ 4,762
Net income (loss)	\$ (2,839)	\$ (240)	\$ (115)	\$ (3,941)	\$ (6,076)
Less: Net income (loss) attributable to noncontrolling interests	254	168	167	133	56
Net income (loss) attributable to Hess Corporation	\$ (3,093) (d)	\$ (408) (e)	\$ (282) (f)	\$ (4,074) (g)	\$ (6,132) (h)
Net Income (Loss) Attributable to Hess Corporation Per Common Share:					
Basic	\$ (10.15)	\$ (1.37)	\$ (1.10)	\$ (13.12)	\$ (19.92)
Diluted	(10.15)	(1.37)	(1.10)	(13.12)	(19.92)
Balance Sheet Selected Financial Data					
Total assets	\$ 18,821	\$ 21,782	\$ 21,433	\$ 23,112	\$ 28,621
Total debt and finance lease obligations (c)	\$ 8,534	\$ 7,397	\$ 6,672	\$ 6,977	\$ 6,806
Total equity	\$ 6,335	\$ 9,706	\$ 10,888	\$ 12,354	\$ 15,591

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Dividends Per Share

Dividends per share of common stock	\$	1.00	\$	1.00	\$	1.00	\$	1.00	\$	1.00
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- (a) Represents sales of Hess net production and purchased third-party volumes.
- (b) Commencing with the adoption of Accounting Standards Codification 606, Revenue from Contracts with Customers, using the modified retrospective method effective January 1, 2018, gains (losses) on commodity derivatives are included within Other operating revenues. Prior to January 1, 2018, gains (losses) on commodity derivatives were included within Crude oil revenues.
- (c) At December 31, 2020 includes debt from our Midstream operating segment of \$1,910 million that is non-recourse to Hess Corporation (2019: \$1,753 million; 2018: \$981 million; 2017: \$980 million; 2016: \$733 million).
- (d) Includes after-tax asset impairment charges of \$2.0 billion, after-tax charges of \$150 million primarily related to the write-off of previously capitalized exploratory wells in the Gulf of Mexico and the write-off of leasehold costs, after-tax charges of \$99 million, related to the reduction of crude oil inventories to their net realizable value, employee termination benefits incurred, and the write-off of right of use assets and surplus materials and supplies inventories, partially offset by an after-tax gain of \$79 million related to the sale of our working interest in the Shenzi Field in the Gulf of Mexico.
- (e) Includes an allocation of noncash income tax expense of \$86 million that was previously a component of accumulated other comprehensive income related to our 2019 crude oil hedge contracts, an after-tax charge of \$88 million related to a pension settlement, a charge after income taxes and noncontrolling interests of \$16 million for transaction related costs for Hess Midstream Partners LP acquisition of HIP and corporate restructuring, and an after-tax charge of \$19 million related to a settlement on historical cost recovery balances in the JDA. These charges were partially offset by a noncash income tax benefit of \$60 million to reverse a valuation allowance against net deferred tax assets in Guyana upon achieving first production, and an after-tax gain of \$22 million related to the sale of our remaining acreage in the Utica shale play.
- (f) Includes after-tax charges of \$221 million related to exit costs, settlement of legal claims related to a former downstream interest, and a loss from debt extinguishment. These charges were, partially offset by a noncash income tax benefit of \$91 million primarily related to intraperiod income tax allocation requirements resulting from changes in fair value of our 2019 crude oil hedging program, and gains totaling \$24 million related to asset sales.
- (g) Includes after-tax asset impairment charges of \$2,250 million, an after-tax dry hole and lease impairment charge of \$280 million, a combined after-tax loss of \$91 million related to asset sales (Norway, Equatorial Guinea and Permian), and after-tax charges of \$52 million primarily for de-designated crude oil hedging contracts and other exit costs.
- (h) Includes noncash charges of \$3,749 million to establish valuation allowances on deferred tax assets following a three-year cumulative loss and after-tax charges of \$894 million primarily for dry hole and other exploration expenses, loss on debt extinguishment, offshore rig costs, severance, and impairment of older specification rail cars.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read together with the *Consolidated Financial Statements* and the *Notes to Consolidated Financial Statements*, which are included in this Form 10-K in Item 8, and the information set forth in [Risk Factors](#) under Item 1A.

The following Management's Discussion and Analysis of Financial Condition and Results of Operations omits certain discussions of our financial condition and results of operations for the year ended December 31, 2018 compared with the year ended December 31, 2019, which can be found in [Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations](#) in our 2019 Annual Report on Form 10-K, which was filed with the Securities and Exchange Commission on February 20, 2020, and such comparisons are incorporated herein by reference.

Index**Overview****Consolidated Results of Operations****Liquidity and Capital Resources****Critical Accounting Policies and Estimates****Overview**

Hess Corporation is a global E&P company engaged in exploration, development, production, transportation, purchase and sale of crude oil, natural gas liquids, and natural gas with production operations located primarily in the United States (U.S.), Guyana, the Malaysia/Thailand Joint Development Area (JDA), Malaysia, and Denmark. We conduct exploration activities primarily offshore Guyana, in the U.S. Gulf of Mexico, and offshore Suriname and Canada. At the Stabroek Block (Hess 30%), offshore Guyana, we have announced eighteen significant discoveries. The Liza Phase 1 development achieved first production in December 2019, and reached its nameplate production capacity of approximately 120,000 gross bopd in December 2020. The Liza Phase 2 development was sanctioned in the second quarter of 2019 and is expected to achieve first production by early 2022, with production capacity of approximately 220,000 gross bopd. A third development, Payara, was sanctioned in the third quarter of 2020 and is expected to achieve first production in 2024, with production capacity of approximately 220,000 gross bopd. The discovered resources to date on the Stabroek Block are expected to underpin up to ten FPSOs with the first five FPSOs producing more than 750,000 gross bopd by 2026.

Our Midstream operating segment, which is comprised of Hess Corporation's 47% consolidated ownership interest in Hess Midstream LP at December 31, 2020, provides fee-based services, including gathering, compressing and processing natural gas and fractionating NGL; gathering, terminaling, loading and transporting crude oil and NGL; storing and terminaling propane, and water handling services primarily in the Bakken shale play in the Williston Basin area of North Dakota.

Hess Response to COVID-19 and Market Conditions

COVID-19 continues to have a profound impact on society and industry. The Corporation's first priority in the midst of the pandemic has been the health and safety of the Hess workforce and local communities where the Corporation operates. A multidisciplinary Hess emergency response team has been overseeing plans and precautions to reduce the risks of COVID-19 in the work environment while maintaining business continuity based on the most current recommendations by government and public health agencies. The Corporation has implemented a variety of health and safety measures including enhanced cleaning procedures and modified work practices such as travel restrictions, health screenings, reduced personnel at offshore platforms and onshore work sites wherever this can be done safely, and remote working arrangements for office workers. In July 2020, Hess Midstream LP announced that the planned maintenance turnaround at the Tioga Gas Plant originally scheduled for the third quarter of 2020 will be deferred until 2021 to ensure safe execution in light of COVID-19.

In addition to the global health concerns of COVID-19, the pandemic has severely impacted demand for oil. Our realized crude oil selling prices, including hedging, were \$44.28 per barrel in 2020 (2019: \$56.77; 2018: \$60.77). In response to the resulting sharp decline in oil prices, the Corporation's focus is on preserving cash and capability, while protecting the long-term value of its assets. In the first quarter of 2020, we reduced our E&P capital and exploratory budget of \$3.0 billion for 2020 to \$1.9 billion, and we ended the year with actual capital and exploratory expenditures of \$1.8 billion. This reduction was achieved primarily by shifting from a six rig program to one rig in the Bakken, which was accomplished in May, deferral of some 2020 development activities on the Stabroek Block, offshore Guyana, and deferring discretionary spending across the portfolio. In March 2020, Hess entered into a \$1.0 billion three year term loan agreement, and in November, we sold our 28% working interest in the Shenzi Field for net proceeds of \$482 million, after closing adjustments.

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2021 Outlook

Our E&P capital and exploratory expenditures are projected to be approximately \$1.9 billion in 2021. Capital investment for our Midstream operations is expected to be approximately \$160 million. Oil and gas net production in 2021 is forecast to be approximately 310,000 boepd excluding Libya. For 2021, we have WTI put options with an average monthly floor price of \$50 per barrel for 120,000 bopd, and Brent put options with an average monthly floor price of \$55 per barrel for 30,000 bopd.

Net cash provided by operating activities was \$1,333 million in 2020, compared with \$1,642 million in 2019, while net cash provided by operating activities before changes in operating assets and liabilities was \$1,803 million in 2020 and \$2,237 million in 2019. Capital expenditures for 2020 and 2019 were \$1,931 million and \$2,992 million, respectively. In 2021, based on current forward strip crude oil prices, we expect cash flow from operating activities, proceeds from the first quarter 2021 sale of 4.2 million barrels of crude oil stored on two VLCCs at year-end, and cash and cash equivalents existing at December 31, 2020 of \$1.74 billion will be sufficient to fund our capital investment program and dividends. Due to the volatile commodity price environment, we may take any of the following steps, or a combination thereof, to improve our liquidity and financial position:

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reduce the planned capital program and other cash outlays, including dividends, pursue asset sales, borrow against our committed revolving credit facility, or issue debt or equity securities.

Consolidated Results

Net loss attributable to Hess Corporation was \$3,093 million in 2020 (2019: \$408 million). Excluding items affecting comparability of earnings between periods summarized on page 33, the adjusted net loss was \$894 million in 2020 (2019: \$281 million). Annual net production averaged 331,000 boepd in 2020 (2019: 311,000 boepd). Total proved reserves were 1,170 million boe at December 31, 2020 (2019: 1,197 million boe).

Significant 2020 Activities

The following is an update of significant E&P activities during 2020:

E&P assets:

- In North Dakota, net production from the Bakken shale play averaged 193,000 boepd in 2020 (2019: 152,000 boepd), with net oil production up 15% to 107,000 bopd from 93,000 bopd primarily due to increased wells online and improved well performance. Natural gas and NGL production also increased from higher wells online, additional natural gas captured and processed, and approximately 7,000 boepd of additional volumes received under percentage of proceeds contracts resulting from lower prices. During the year, we operated six rigs in the Bakken through May, before reducing to one rig for the remainder of 2020 in response to the sharp decline in oil prices resulting from the COVID-19 pandemic. We drilled 71 wells and brought 111 wells on production, bringing the total operated production wells to 1,686 by year-end. We reduced the average cost of a plug and perf well in 2020 to \$6.2 million per well from \$6.8 million per well in 2019. We forecast net production from the Bakken to average approximately 170,000 boepd in 2021.

In the second quarter, we chartered three VLCCs and loaded a total of 6.3 million barrels of oil for sale in Asian markets to enhance cash flow and maximize value from our Bakken production. The first VLCC cargo of 2.1 million barrels was sold in China in September. We have agreements in place to sell the remaining two VLCC cargos totaling 4.2 million barrels in the first quarter of 2021. We expect to recognize net income of approximately \$60 million in the first quarter of 2021 from these sales, including associated hedging gains and costs.

- In the Gulf of Mexico, net production averaged 56,000 boepd (2019: 66,000 boepd) reflecting the effect of increased hurricane-related downtime, higher planned maintenance and lower production from the Shenzi Field, which was sold in November 2020, partially offset by initial production from the Esox-1 well, which commenced in February of 2020. Net production from the Shenzi Field was 9,000 boepd in 2020 (2019: 12,000 boepd). We forecast Gulf of Mexico net production for 2021 to average approximately 45,000 boepd.

We participated in two outside operated exploration wells that were completed in 2020, the Oldfield-1 well and the Galapagos Deep well, both located in the Mississippi Canyon area. Both wells were unsuccessful.

- At the Stabroek Block (Hess 30%), offshore Guyana, net production from the Liza Phase 1 development averaged 20,000 bopd in 2020 following first production in December 2019 from the Liza Destiny FPSO. During the fourth quarter, the operator Esso Exploration and Production Guyana Limited, reached its nameplate capacity of 120,000 gross bopd. For 2021, net production from Guyana is expected to average approximately 30,000 bopd.

The Liza Phase 2 development was sanctioned in 2019 and will utilize the Liza Unity FPSO to produce up to 220,000 gross bopd, with first production expected by early 2022. A total of 30 wells are planned at six drill centers, including 15 production wells, nine water injection wells and six gas injection wells. In 2021, the operator plans to continue development

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drilling, complete installation of subsea flow lines and equipment, complete installation of topside facilities on the FPSO and sail the Liza Unity FPSO from Singapore to the Liza Field.

On September 30, 2020, we announced the final investment decision to proceed with development of the Payara Field on the Stabroek Block after the development plan received approval from the government of Guyana. Payara will utilize the Prosperity FPSO, which will have the capacity to produce up to 220,000 gross bopd, with first production expected in 2024. Ten drill centers with a total of 41 wells are planned, including 20 production wells and 21 injection wells. Excluding pre-sanction costs and FPSO purchase cost, our net share of development costs is forecast to be approximately \$1.8 billion.

In addition to the first three developments, planning is underway for additional FPSOs. The ultimate sizing and timing of these potential developments will be a function of further exploration and appraisal drilling.

In 2020, two successful exploration wells and one successful appraisal well were drilled on the Stabroek Block. For 2021, the operator plans to bring in a fifth drillship in March and a sixth drillship in April and drill 12 to 15 exploration and appraisal wells during the year.

- At the Kaieteur Block (Hess 15%), offshore Guyana, the operator, Esso Exploration and Production Guyana Limited, completed drilling of the Tanager-1 exploration well. The well did encounter hydrocarbons but was not a commercial success on a stand-alone basis.
- In the Gulf of Thailand, net production from Block A-18 of the JDA averaged 29,000 boepd for the year (2019: 35,000 boepd), including

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contribution from unitized acreage in Malaysia, while net production from North Malay Basin averaged 23,000 boepd for the year (2019: 28,000 boepd). During 2020, we drilled seven production wells at North Malay Basin, and plan to continue the drilling program and development activities in 2021. We also expect to commence a multi-year drilling program in the first half of 2021 at the JDA. Combined net production from our JDA and North Malay Basin assets is forecast to average approximately 60,000 boepd in 2021.

The following is an update of significant Midstream activities during 2020:

- In 2019, Hess Midstream LP announced plans to expand processing capacity at the Tioga Gas Plant by 150 mmcf/d for total processing capacity of 400 mmcf/d. In 2020, the facility construction was completed for the expansion. The incremental gas processing capacity is expected to be available in 2021 upon completion of a scheduled plant maintenance turnaround, during which the expansion and residue and NGL takeaway pipelines will be tied in. The plant maintenance turnaround was originally planned to occur in the third quarter of 2020 but was deferred to 2021 to ensure safe execution in light of the COVID-19 pandemic.
- On December 30, 2020, Hess Midstream LP exercised its renewal options to extend the terms of certain gas gathering, crude oil gathering, gas processing and fractionation, storage, and terminal and export commercial agreements for the secondary term through December 31, 2033. There were no changes to any provisions of the existing commercial agreements as a result of the exercise of the renewal options.

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Liquidity and Capital and Exploratory Expenditures

In 2020, net cash provided by operating activities was \$1,333 million (2019: \$1,642 million). At December 31, 2020, cash and cash equivalents were \$1,739 million (2019: \$1,545 million), consolidated debt was \$8,296 million (2019: \$7,142 million), and our debt to capitalization ratio (as defined in the credit agreement for our revolving credit facility and the term loan agreement) was 47.5% (2019: 39.6%). Hess Midstream debt, which is nonrecourse to Hess Corporation, was \$1,910 million at December 31, 2020 (2019: \$1,753 million).

Capital and exploratory expenditures were as follows (in millions):

	2020	2019	2018
E&P Capital and Exploratory Expenditures:			
United States			
North Dakota	\$ 661	\$ 1,312	\$ 967
Offshore and other	258	471	411
Total United States	919	1,783	1,378
Guyana	743	783	383
Malaysia and JDA	99	109	123
Other (a)	25	68	185
E&P Capital and Exploratory Expenditures	<u>\$ 1,786</u>	<u>\$ 2,743</u>	<u>\$ 2,069</u>
Exploration Expenses Charged to Income Included Above:			
United States	\$ 91	\$ 105	\$ 106
International	17	62	54
Total Exploration Expenses Charged to Income included above	<u>\$ 108</u>	<u>\$ 167</u>	<u>\$ 160</u>
Midstream Capital Expenditures:			
Midstream Capital Expenditures (b)	<u>\$ 253</u>	<u>\$ 416</u>	<u>\$ 271</u>

(a) Other includes our interests in Denmark, Libya and other non-producing countries.

(b) Excludes equity investments of \$33 million in 2019 and \$67 million in 2018.

In 2021, we project our E&P capital and exploratory expenditures will be approximately \$1.9 billion and Midstream capital expenditures to be approximately \$160 million.

Consolidated Results of Operations

Results by Segment:

The after-tax income (loss) by major operating activity is summarized below:

	2020	2019	2018
	(In millions, except per share amounts)		
Net Income (Loss) Attributable to Hess Corporation:			
Exploration and Production	\$ (2,841)	\$ 53	\$ 51

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Midstream	230	144	120
Corporate, Interest and Other	(482)	(605)	(453)
Total	\$ (3,093)	\$ (408)	\$ (282)
Net Income (Loss) Attributable to Hess Corporation Per Common Share - Diluted (a)	\$ (10.15)	\$ (1.37)	\$ (1.10)

(a) Calculated as net income (loss) attributable to Hess Corporation less preferred stock dividends, divided by weighted average number of diluted shares.

In the following discussion and elsewhere in this report, the financial effects of certain transactions are disclosed on an after-tax basis. Management reviews segment earnings on an after-tax basis and uses after-tax amounts in its review of variances in segment earnings. Management believes that after-tax amounts are a preferable method of explaining variances in earnings, since they show the entire effect of a transaction rather than only the pre-tax amount. After-tax amounts are determined by applying the income tax rate in each tax jurisdiction to pre-tax amounts.

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Items Affecting Comparability of Earnings Between Periods:

The following table summarizes items of income (expense) that are included in net income (loss) and affect comparability of earnings between periods. The items in the table below are explained on pages 38 through 41.

	2020	2019	2018
	(In millions)		
Items Affecting Comparability of Earnings Between Periods, After Income Taxes:			
Exploration and Production	\$ (2,198)	\$ 63	\$ (86)
Midstream	—	(16)	—
Corporate, Interest and Other	(1)	(174)	(20)
Total	\$ (2,199)	\$ (127)	\$ (106)

The following table presents the pre-tax amount of items affecting comparability of income (expense) by financial statement line item in the *Statement of Consolidated Income* on page 57. The items in the table below are explained on pages 38 through 41.

	Before Income Taxes		
	2020	2019	2018
	(In millions)		
Gains on asset sales, net	\$ 79	\$ 22	\$ 24
Other, net	—	(88)	—
Marketing, including purchased oil and gas	(53)	(21)	—
Operating costs and expenses	(20)	—	(19)
Exploration expenses, including dry holes and lease impairment	(153)	—	(3)
General and administrative expenses	(6)	(30)	(130)
Loss on debt extinguishment	—	—	(53)
Depreciation, depletion and amortization	—	—	(16)
Impairment	(2,126)	—	—
Total Items Affecting Comparability of Earnings Between Periods, Pre-Tax	\$ (2,279)	\$ (117)	\$ (197)

Reconciliations of GAAP and Non-GAAP Measures:

The following table reconciles reported net income (loss) attributable to Hess Corporation and adjusted net income (loss) attributable to Hess Corporation:

	2020	2019	2018
	(In millions)		
Adjusted Net Income (Loss) Attributable to Hess Corporation:			
Net income (loss) attributable to Hess Corporation	\$ (3,093)	\$ (408)	\$ (282)
Less: Total items affecting comparability of earnings between periods, after-tax	(2,199)	(127)	(106)
Adjusted Net Income (Loss) Attributable to Hess Corporation	\$ (894)	\$ (281)	\$ (176)

The following table reconciles reported net cash provided by (used in) operating activities and net cash provided by (used in) operating activities before changes in operating assets and liabilities:

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	2020	2019	2018
	(In millions)		
Net cash provided by operating activities before changes in operating assets and liabilities:			
Net cash provided by (used in) operating activities	\$ 1,333	\$ 1,642	\$ 1,939
Changes in operating assets and liabilities	470	595	190
Net cash provided by (used in) operating activities before changes in operating assets and liabilities	\$ 1,803	\$ 2,237	\$ 2,129

Adjusted net income (loss) attributable to Hess Corporation is a non-GAAP financial measure, which we define as reported net income (loss) attributable to Hess Corporation excluding items identified as affecting comparability of earnings between periods, which are summarized on pages 38 through 41. Management uses adjusted net income (loss) to evaluate the Corporation's operating performance and believes that investors' understanding of our performance is enhanced by disclosing this measure, which excludes certain items that management believes are not directly related to ongoing operations and are not indicative of future business trends and operations.

Net cash provided by (used in) operating activities before changes in operating assets and liabilities presented in this report is a non-GAAP measure, which we define as reported net cash provided by (used in) operating activities excluding changes in operating assets and liabilities. Management uses net cash provided by (used in) operating activities before changes in operating assets and

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liabilities to evaluate the Corporation's ability to internally fund capital expenditures, pay dividends and service debt and believes that investors' understanding of our ability to generate cash to fund these items is enhanced by disclosing this measure, which excludes working capital and other movements that may distort assessment of our performance between periods.

These measures are not, and should not be viewed as, substitutes for U.S. GAAP net income (loss) and net cash provided by (used in) operating activities.

Comparison of Results

Exploration and Production

Following is a summarized statement of income for our E&P operations:

	2020	2019	2018
	(In millions)		
Revenues and Non-Operating Income			
Sales and other operating revenues	\$ 4,667	\$ 6,495	\$ 6,323
Gains on asset sales, net	79	22	27
Other, net	31	51	53
Total revenues and non-operating income	4,777	6,568	6,403
Costs and Expenses			
Marketing, including purchased oil and gas	1,067	1,849	1,833
Operating costs and expenses	895	971	941
Production and severance taxes	124	184	171
Midstream tariffs	946	722	648
Exploration expenses, including dry holes and lease impairment	351	233	362
General and administrative expenses	206	204	258
Depreciation, depletion and amortization	1,915	1,977	1,748
Impairment	2,126	—	—
Total costs and expenses	7,630	6,140	5,961
Results of Operations Before Income Taxes	(2,853)	428	442
Provision (benefit) for income taxes (a)	(12)	375	391
Net Income (Loss) Attributable to Hess Corporation	\$ (2,841)	\$ 53	\$ 51

(a) Commencing January 1, 2019, management changed its measurement of segment earnings to reflect income taxes on a post U.S. tax consolidation and valuation allowance assessment basis. See footnote (a) in the table on page 87 for further details.

Excluding the E&P items affecting comparability of earnings between periods in the table on page 38, the changes in E&P results are primarily attributable to changes in selling prices, production and sales volumes, marketing expenses, cash operating costs, Midstream tariffs, DD&A, exploration expenses and income taxes, as discussed below.

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Selling Prices: Average worldwide realized crude oil selling prices, including hedging, were 22% lower in 2020 compared with the prior year, primarily due to the decrease in Brent and WTI crude oil prices. In addition, realized worldwide selling prices for NGL decreased in 2020 by 16% and worldwide natural gas prices decreased in 2020 by 24%, compared with the prior year. In total, lower realized selling prices decreased financial results by approximately \$780 million after income taxes, compared with 2019. Our average selling prices were as follows:

	2020	2019	2018
Average Selling Prices (a)			
Crude Oil - Per Barrel (Including Hedging)			
United States			
North Dakota	\$ 42.63	\$ 53.19	\$ 56.90
Offshore	45.92	59.18	62.02
Total United States	43.56	55.15	58.69
Guyana	46.41	—	—
Malaysia and JDA	37.91	61.81	70.42
Other (b)	51.37	65.22	69.76
Worldwide	44.28	56.77	60.77
Crude Oil - Per Barrel (Excluding Hedging)			
United States			
North Dakota	\$ 33.87	\$ 53.18	\$ 60.64
Offshore	36.55	59.17	65.73
Total United States	34.63	55.14	62.41
Guyana	37.40	—	—
Malaysia and JDA	37.91	61.81	70.42
Other (b)	43.42	65.22	69.76
Worldwide	35.52	56.76	63.80
Natural Gas Liquids - Per Barrel			
United States			
North Dakota	\$ 11.29	\$ 13.20	\$ 21.48
Other Onshore (c)	—	—	18.55
Offshore	8.94	13.31	25.58
Worldwide	11.10	13.21	21.81
Natural Gas - Per Mcf			
United States			
North Dakota	\$ 1.27	\$ 1.59	\$ 2.42
Other Onshore (c)	—	—	2.02
Offshore	1.23	2.12	2.68
Total United States	1.26	1.83	2.43
Malaysia and JDA	4.47	5.04	5.07
Other (b)	3.41	4.63	4.41
Worldwide	2.98	3.90	4.18

(a) Selling prices in the United States are adjusted for certain processing and distribution fees included in Marketing expenses. Excluding these fees worldwide selling prices for 2020 would be \$47.54 per barrel for crude oil (including hedging) (2019: \$59.95; 2018: \$63.77), \$38.78 per barrel for crude oil (excluding hedging) (2019: \$59.94; 2018: \$66.80), \$11.29 per barrel for NGL (2019: \$13.40; 2018: \$22.00) and \$3.11 per mcf for natural gas (2019: \$3.97; 2018: \$4.25).

(b) Other includes our interests in Denmark and Libya.

(c) In August 2018, we sold our interests in the Utica shale play, onshore U.S.

Crude oil hedging activities in 2020 were a net gain of \$547 million before and after income taxes, and a net gain of \$1 million before and after income taxes in 2019. For 2021, we have WTI put options with an average monthly floor price of \$50 per barrel for 120,000 bopd, and Brent put options with an average monthly floor price of \$55 per barrel for 30,000 bopd. We expect put option premium amortization, which will be reflected in realized selling prices, to reduce our 2021 results by approximately \$205 million.

Production Volumes: Our daily worldwide net production was as follows:

	2020	2019	2018
	(In thousands)		
Crude Oil - Barrels			
United States			
North Dakota	107	94	77
Offshore (a)	38	46	41
Total United States	145	140	118
Guyana	20	—	—
Malaysia and JDA	4	4	4
Other (b)	9	25	24
Total	178	169	146
Natural Gas Liquids - Barrels			
United States			
North Dakota	56	42	31
Other Onshore (c)	—	—	3
Total Onshore	56	42	34
Offshore (a)	5	5	5
Total United States	61	47	39
Natural Gas - Mcf			
United States			
North Dakota	180	110	76
Other Onshore (c)	—	—	38
Total Onshore	180	110	114
Offshore (a)	76	91	67
Total United States	256	201	181
Malaysia and JDA	291	351	352
Other (b)	7	20	20
Total	554	572	553
Barrels of Oil Equivalent	331	311	277
Crude oil and natural gas liquids as a share of total production	72 %	69 %	67 %

(a) In November 2020, we sold our working interest in the Shenzi Field in the deepwater Gulf of Mexico. Net production from the Shenzi Field was 9,000 boepd for the year ended December 31, 2020 (2019: 12,000 boepd; 2018: 16,000 boepd).

(b) Other includes our interests in Denmark and Libya. Net production from Libya was 4,000 boepd for 2020 (2019: 21,000 boepd; 2018: 20,000 boepd). Net production from Denmark was 6,000 boepd for 2020 (2019: 7,000 boepd; 2018: 7,000 boepd).

(c) In August 2018, we sold our interests in the Utica shale play, onshore U.S. Production was 9,000 boepd for the year ended December 31, 2018.

In 2021, we expect net production, excluding Libya, to be approximately 310,000 boepd, compared with 2020 net production, excluding Libya and assets sold, of 318,000 boepd.

Net production variances related to 2020 and 2019 are summarized as follows:

United States: North Dakota net oil production was higher in 2020, primarily due to increased wells online and improved well performance. North Dakota net natural gas and NGL production was higher in 2020, due to increased wells online and improved well performance, additional natural gas captured and processed, and additional volumes received under percentage of proceeds contracts resulting from lower prices. Offshore net production was down in 2020 compared to 2019 due to the effect of increased hurricane-related downtime and higher planned maintenance in 2020 and lower production from the Shenzi Field, which was sold in November 2020, partially offset by initial production from the Esos-1 well, which commenced in February of 2020.

International: Net crude oil production from Guyana was higher in 2020, due to the start-up of the Liza Phase 1 development in December 2019, while net crude oil production in Libya was largely shut in during 2020 due to force majeure caused by civil unrest. Net natural gas production was lower from Malaysia and JDA due to COVID-19 impacts on economic activity in Malaysia and Thailand which reduced natural gas nominations from the buyers.

Sales Volumes: Higher sales volumes from our net production in 2020 improved after-tax results by approximately \$130 million, compared with 2019. Net worldwide sales volumes from Hess net production, which excludes sales volumes of crude oil, NGL and natural gas purchased from third parties, were as follows:

	2020	2019	2018
	(In thousands)		
Crude oil – barrels (a)	60,924	61,061	52,742
Natural gas liquids – barrels	22,397	17,067	14,019
Natural gas – mcf	202,917	208,665	202,041
Barrels of Oil Equivalent	117,141	112,906	100,435
Crude oil - barrels per day	167	167	144
Natural gas liquids - barrels per day	61	47	39
Natural gas - mcf per day	554	572	553
Barrels of Oil Equivalent Per Day	320	309	275

(a) In 2020, 6.3 million barrels of Bakken crude oil were loaded on VLCCs for sale in Asian markets. The first VLCC cargo of 2.1 million barrels was sold during the third quarter of 2020 and the remaining two VLCC cargos totaling 4.2 million barrels have been sold for delivery in the first quarter of 2021.

Marketing, including purchased oil and gas (Marketing expense): Marketing expense is mainly comprised of costs to purchase crude oil, NGL and natural gas from our partners in Hess operated wells or other third parties, primarily in the U.S., and transportation and other distribution costs for U.S. marketing activities. Marketing expense was lower in 2020 compared to 2019 primarily due to lower crude oil prices paid for purchased volumes from third parties.

Cash Operating Costs: Cash operating costs consist of operating costs and expenses, production and severance taxes and E&P general and administrative expenses. Excluding items affecting comparability described in *Items Affecting Comparability of Earnings Between Periods* below, cash operating costs decreased \$159 million, or 12%, in 2020 compared to 2019 primarily from the impact of cost reduction initiatives and lower production and severance taxes associated with lower crude oil prices. On a per-unit basis, cash operating costs improved 17% from 2019 reflecting lower costs and the impact of higher production volumes.

Midstream Tariffs Expense: Tariffs expense increased from 2019, primarily due to higher throughput volumes and tariff rates in 2020. In 2021, we estimate Midstream tariffs expense to be in the range of \$1,090 million to \$1,115 million.

DD&A: DD&A expenses decreased by \$62 million from 2019, primarily due to a lower portfolio average DD&A rate, due in part to impairment charges in the first quarter of 2020, partially offset by higher production volumes. DD&A expense on a per-unit basis was lower in 2020, compared to 2019, primarily due to the year-over-year mix of production and the impact of reduced DD&A rates for assets impaired in the first quarter of 2020.

Unit costs: Unit cost per boe information is based on total E&P net production volumes and excludes items affecting comparability of earnings as disclosed below. Actual and forecast unit costs are as follows:

	Actual			Forecast range (a)
	2020	2019	2018	2021
Cash operating costs (b)	\$ 9.91	\$ 11.99	\$ 12.66	\$10.50 — \$11.50
DD&A (c)	15.80	17.43	17.14	12.00 — 13.00
Total Production Unit Costs	\$ 25.71	\$ 29.42	\$ 29.80	\$22.50 — \$24.50

(a) Forecast information excludes any contribution from Libya.

(b) Cash operating costs per boe, excluding Libya, was \$9.85 in 2020 (2019: \$12.54; 2018: \$13.32).

(c) DD&A per boe, excluding Libya, was \$15.98 in 2020 (2019: \$18.52; 2018: \$18.29).

Exploration Expenses: Exploration expenses, including items affecting comparability of earnings described below, were as follows:

	2020	2019	2018
	(In millions)		
Exploratory dry hole costs (a)	\$ 192	\$ 49	\$ 165

Exploration lease and other impairment (b)
Geological and geophysical expense and exploration overhead

	51	17	37
	108	167	160
\$	351	\$ 233	\$ 362

- (a) In 2020, dry hole costs primarily related to the Tanager-1 well in the Kaieteur Block, offshore Guyana, the Galapagos Deep and Oldfield-1 wells in the Gulf of Mexico and the write-off of previously capitalized exploratory wells (see *Items Affecting Comparability of Earnings Between Periods* below). In 2019, dry hole costs primarily related to the Jill-1 well on License 6/16 in Denmark and the Oldfield-1 well in the Gulf of Mexico. Dry hole expense for the Oldfield-1 well was \$15 million in 2019 and \$12 million in 2020.
- (b) In 2020, exploration lease and other impairment included impaired leasehold costs due to a reprioritization of the Corporation's forward capital program (see *Items Affecting Comparability of Earnings Between Periods* below).

In 2021, we estimate exploration expenses, excluding dry hole expense, to be in the range of \$170 million to \$180 million.

Income Taxes: In 2020, income tax benefit was \$12 million compared with expense of \$375 million in 2019, primarily due to reduced activity in Libya resulting from force majeure on operations for the majority of the year. We are generally not recognizing deferred tax benefit or expense in certain countries, primarily the U.S., Denmark, and Malaysia, while we maintain valuation allowances against net deferred tax assets in these jurisdictions in accordance with the requirements of U.S. accounting standards. The valuation allowance established against the net deferred tax asset in Guyana for the Stabroek Block was released as a result of the positive evidence from first production in December 2019, and the significant forecasted pre-tax income from operations. The cumulative pre-tax losses in Guyana were driven by pre-production activities. See E&P *Items Affecting Comparability of Earnings Between Periods* below.

Actual effective tax rates are as follows:

	2020	2019	2018
	%	%	%
Effective income tax benefit (expense) rate	0	(88)	(88)
Adjusted effective income tax benefit (expense) rate (a)	(5)	(36)	60

- (a) Excludes any contribution from Libya and items affecting comparability of earnings.

In 2021, we estimate income tax expense, excluding Libya and items affecting comparability of earnings between periods, to be in the range of \$80 million to \$90 million.

Items Affecting Comparability of Earnings Between Periods: Reported E&P earnings include the following items affecting comparability of income (expense):

	Before Income Taxes			After Income Taxes		
	2020	2019	2018	2020	2019	2018
	(In millions)					
Impairment	\$ (2,126)	\$ —	\$ —	\$ (2,049)	\$ —	\$ —
Dry hole and lease impairment expenses	(152)	—	—	(150)	—	—
Crude oil inventories write-down	(53)	—	—	(52)	—	—
Exit costs and other	(26)	—	(110)	(26)	—	(110)
Cost recovery settlement	—	(21)	—	—	(19)	—
Reversal of deferred tax asset valuation allowance	—	—	—	—	60	—
Gains on asset sales, net	79	22	24	79	22	24
	<u>\$ (2,278)</u>	<u>\$ 1</u>	<u>\$ (86)</u>	<u>\$ (2,198)</u>	<u>\$ 63</u>	<u>\$ (86)</u>

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The pre-tax amounts of E&P items affecting comparability of income (expense) as presented in the *Statement of Consolidated Income* are as follows:

	Before Income Taxes		
	2020	2019	2018
	(In millions)		
Gains on asset sales, net	\$ 79	\$ 22	\$ 24
Marketing, including purchased oil and gas	(53)	(21)	—
Operating costs and expenses	(20)	—	(19)
Exploration expenses, including dry holes and lease impairment	(153)	—	(3)
General and administrative expenses	(5)	—	(72)
Depreciation, depletion and amortization	—	—	(16)
Impairment	(2,126)	—	—

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\$ (2,278) \$ 1 \$ (86)

2020:

- *Impairment:* We recorded noncash impairment charges totaling \$2.1 billion (\$2.0 billion after income taxes) related to our oil and gas properties at North Malay Basin in Malaysia, the South Arne Field in Denmark, and the Stampede and Tubular Bells fields in the Gulf of Mexico, primarily as a result of a lower long-term crude oil price outlook. Other charges totaling \$21 million pre-tax (\$20 million after income taxes) related to drilling rig right-of-use assets in the Bakken and surplus materials and supplies. See *Note 12, Impairment* in the *Notes to Consolidated Financial Statements*.
- *Dry hole and lease impairment expenses:* We incurred pre-tax charges totaling \$152 million (\$150 million after income taxes) in the first quarter to write-off previously capitalized exploratory well costs of \$125 million (\$123 million after income taxes) primarily related to the northern portion of the Shenzi Field in the Gulf of Mexico and to impair certain exploration leasehold costs by \$27 million (\$27 million after income taxes) due to a reprioritization of our capital program.
- *Crude oil inventories write-down:* We incurred a pre-tax charge of \$53 million (\$52 million after income taxes) to adjust crude oil inventories to their net realizable value at the end of the first quarter following the significant decline in crude oil prices.
- *Exit costs and other:* We recorded a pre-tax charge of \$26 million (\$26 million after income taxes) for employee termination benefits incurred related to cost reduction initiatives.
- *Gains on asset sales, net:* We recorded a pre-tax gain of \$79 million (\$79 million after income taxes) associated with the sale of our 28% working interest in the Shenzi Field in the deepwater Gulf of Mexico.

2019:

- *Cost recovery settlement:* We recorded a pre-tax charge of \$21 million (\$19 million after income taxes) related to a settlement on historical cost recovery balances in the JDA that was paid in cash.
- *Reversal of deferred tax asset valuation allowance:* We recorded a noncash income tax benefit of \$60 million, which resulted from the reversal of a valuation allowance against net deferred tax assets in Guyana upon achieving first production from the Liza Phase 1 development.
- *Gains on asset sales, net:* We recorded a pre-tax gain of \$22 million (\$22 million after income taxes) associated with the sale of our remaining acreage in the Utica shale play.

2018:

- *Exit costs and other:* We incurred noncash pre-tax charges of \$73 million (\$73 million after income taxes) in connection with vacated office space. In addition, we recorded a pre-tax charge of \$37 million (\$37 million after income taxes) for employee termination benefits related to a cost reduction program undertaken to reflect the reduced scale of our business following significant asset sales in 2017.
- *Gains on asset sales, net:* We recorded a pre-tax gain of \$14 million (\$14 million after income taxes) associated with the sale of our joint venture interests in the Utica shale play in eastern Ohio and a pre-tax gain of \$10 million (\$10 million after income taxes) associated with the sale of our interests in Ghana.

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Midstream

Following is a summarized statement of income for our Midstream operations:

	2020	2019	2018
	(In millions)		
Revenues and Non-Operating Income			
Sales and other operating revenues	\$ 1,092	\$ 848	\$ 713
Other, net	10	4	6
Total revenues and non-operating income	<u>1,102</u>	<u>852</u>	<u>719</u>
Costs and Expenses			
Operating costs and expenses	338	279	193
General and administrative expenses	21	56	14
Depreciation, depletion and amortization	157	142	127
Interest expense	95	63	60
Total costs and expenses	<u>611</u>	<u>540</u>	<u>394</u>
Results of Operations Before Income Taxes	<u>491</u>	312	325

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Provision (benefit) for income taxes (a)	7	—	38
Net income (loss)	484	312	287
Less: Net income (loss) attributable to noncontrolling interests	254	168	167
Net Income (Loss) Attributable to Hess Corporation	\$ 230	\$ 144	\$ 120

(a) Commencing January 1, 2019, management changed its measurement of segment earnings to reflect income taxes on a post U.S. tax consolidation and valuation allowance assessment basis. See footnote (a) in the table on page 87 for further details.

Sales and other operating revenues increased from 2019 primarily due to higher throughput volumes and tariff rates. Operating costs and expenses increased from 2019 primarily due to increased operating and maintenance expenditures on expanded infrastructure and initial costs incurred related to the Tioga Gas Plant turnaround planned for 2021. General and administrative expenses decreased from 2019 as a result of expenditures incurred from Hess Midstream LP's acquisition of HIP and its corporate restructuring. See *Items Affecting Comparability of Earnings* below. DD&A expenses increased from 2019 primarily due to additional assets placed in service. The increase in interest expense from 2019 reflects higher borrowings by the Midstream business.

In 2021, we estimate net income attributable to Hess Corporation from the Midstream segment to be in the range of \$280 million to \$290 million.

Items Affecting Comparability of Earnings Between Periods: In 2019, we recognized a pre-tax charge of \$30 million (\$16 million after income taxes and noncontrolling interests) in *General and Administrative Expenses* for transaction related costs for Hess Midstream Partners LP's acquisition of HIP and the associated corporate restructuring. See *Note 4, Hess Midstream LP* in the *Notes to Consolidated Financial Statements*.

Corporate, Interest and Other

The following table summarizes Corporate, Interest and Other expenses:

	2020	2019	2018
	(In millions)		
Corporate and other expenses (excluding items affecting comparability)	\$ 114	\$ 114	\$ 97
Interest expense	373	355	359
Less: Capitalized interest	—	(38)	(20)
Interest expense, net	373	317	339
Corporate, Interest and Other expenses before income taxes	487	431	436
Provision (benefit) for income taxes	(6)	—	(3)
Net Corporate, Interest and Other expenses after income taxes	481	431	433
Items affecting comparability of earnings between periods, after income taxes	1	174	20
Total Corporate, Interest and Other Expenses After Income Taxes	\$ 482	\$ 605	\$ 453

Corporate and other expenses, excluding items affecting comparability, were comparable in 2020 compared to the corresponding period in 2019. In 2021, after-tax Corporate and other expenses, excluding items affecting comparability of earnings between periods, are estimated to be in the range of \$130 million to \$140 million.

Interest expense, net was higher in 2020 due to interest incurred on the \$1.0 billion three year term loan entered into in March 2020 and lower capitalized interest. In 2021, after-tax interest expense, net is estimated to be in the range of \$380 million to \$390 million.

Items Affecting Comparability of Earnings Between Periods: Corporate, Interest and Other results included the following items affecting comparability of income (expense):

2020:

- *Exit costs and other:* We included a pre-tax charge of \$1 million (\$1 million after income taxes) for employee termination benefits related to cost reduction initiatives.

2019:

- *Pension settlement:* We recorded a noncash pension settlement charge of \$88 million (\$88 million after income taxes) associated with the purchase of a single premium annuity contract by the Hess Corporation Employees' Pension Plan to settle and transfer certain of its obligations to a third party. The charge is included in *Other, net* in the *Statement of Consolidated Income*.
- *Income tax:* We recorded an allocation of noncash income tax expense of \$86 million that was previously a component of accumulated other comprehensive income related to our 2019 crude oil hedge contracts.

2018:

- *Loss on debt extinguishment:* We recorded a pre-tax charge of \$53 million (\$53 million after income taxes) related to the premium paid for debt repurchases.
- *Exit costs and other:* We recorded a pre-tax charge of \$58 million (\$58 million after income taxes) resulting from the settlement of legal claims related to former downstream interests.
- *Income tax:* We recorded an allocation of noncash income tax benefit of \$91 million to offset the recognition of a noncash income tax expense recorded in other comprehensive income resulting primarily from changes in fair value of our 2019 crude oil hedge contracts.

Liquidity and Capital Resources

The following table sets forth certain relevant measures of our liquidity and capital resources at December 31:

	2020	2019
	(In millions, except ratio)	
Cash and cash equivalents (a)	\$ 1,739	\$ 1,545
Current maturities of long-term debt	10	—
Total debt (b)	8,296	7,142
Total equity	6,335	9,706
Debt to capitalization ratio for debt covenants (c)	47.5 %	39.6 %

(a) Includes \$4 million of cash attributable to our Midstream Segment at December 31, 2020 (2019: \$3 million).

(b) Includes \$1,910 million of debt outstanding from our Midstream Segment at December 31, 2020 (2019: \$1,753 million) that is non-recourse to Hess Corporation.

(c) Total Consolidated Debt of Hess Corporation (including finance leases and excluding Midstream non-recourse debt) as a percentage of Total Capitalization of Hess Corporation as defined under Hess Corporation's term loan and revolving credit facility financial covenants. Total Capitalization excludes the impact of noncash impairment charges and non-controlling interests. See Note 7 in the Notes to Consolidated Financial Statements.

Cash Flows

The following table sets forth a summary of our cash flows:

	2020	2019	2018
	(In millions)		
Net cash provided by (used in):			
Operating activities	\$ 1,333	\$ 1,642	\$ 1,939
Investing activities	(1,707)	(2,843)	(1,566)
Financing activities	568	52	(2,526)
Net Increase (Decrease) in Cash and Cash Equivalents	<u>\$ 194</u>	<u>\$ (1,149)</u>	<u>\$ (2,153)</u>

Operating Activities: Net cash provided by operating activities was \$1,333 million in 2020 (2019: \$1,642 million), while net cash provided by operating activities before changes in operating assets and liabilities was \$1,803 million in 2020 (2019: \$2,237 million). Net cash provided by operating activities before changes in operating assets and liabilities decreased from 2019 primarily due to lower realized selling prices. Changes in operating assets and liabilities in 2020 reduced net cash provided by operating activities by \$470 million, primarily from a decrease in accounts payable and accrued liabilities, an increase in crude oil inventory resulting from our VLCC transactions, and abandonment expenditures, partially offset by lower receivables. Changes in operating

assets and liabilities in 2019 reduced net cash provided by operating activities by \$595 million primarily related to premiums on crude oil hedge contracts, abandonment expenditures, pension contributions and an increase in accounts receivable.

Investing Activities: Total Additions to Property, Plant and Equipment were \$2,197 million in 2020 (2019: \$2,829 million). The decrease primarily reflects lower drilling activity in the Bakken, partially offset by payments in the first quarter of 2020 to settle capital expenditures accrued in the fourth quarter of 2019. In 2019, Midstream equity investments in its 50/50 joint venture with Targa Resources were \$33 million. Proceeds from asset sales were \$493 million in 2020 (2019: \$22 million).

Financing Activities: Borrowings in 2020 related to our \$1.0 billion three year term loan while borrowings in 2019 related to our Midstream operating segment. Repayments of debt were \$8 million in 2019. Net borrowings (repayments) of debt with maturities of 90 days or less related to our Midstream operating segment revolving credit facilities. Common stock dividends paid were \$309 million in 2020 compared to common and preferred dividends of \$316 million in 2019. Net cash outflows to noncontrolling interests were \$261 million in 2020 (2019: \$353 million).

Future Capital Requirements and Resources

At December 31, 2020, Hess Corporation, had \$1.74 billion in cash and cash equivalents, excluding Midstream, and total liquidity, including

available committed credit facilities, of approximately \$5.4 billion. Our fully undrawn \$3.5 billion committed revolving credit facility matures in May 2023, and we have no debt maturities until 2023 when the three year term loan matures.

Net production in 2021 is forecast to be approximately 310,000 boepd, excluding Libya, and we expect our 2021 E&P capital and exploratory expenditures will be approximately \$1.9 billion. For 2021, we have WTI put options with an average monthly floor price of \$50 per barrel for 120,000 bopd, and Brent put options with an average monthly floor price of \$55 per barrel for 30,000 bopd.

In 2021, based on current forward strip crude oil prices, we expect cash flow from operating activities, proceeds from the first quarter 2021 sale of 4.2 million barrels of crude oil stored on two VLCCs at year-end, and cash and cash equivalents existing at December 31, 2020 of \$1.74 billion, will be sufficient to fund our capital investment program and dividends. Due to the volatile commodity price environment, we may take any of the following steps, or a combination thereof, to improve our liquidity and financial position: reduce the planned capital program and other cash outlays, including dividends, pursue asset sales, borrow against our committed revolving credit facility, or issue debt or equity securities.

The table below summarizes the capacity, usage, and available capacity of our borrowing and letter of credit facilities at December 31, 2020:

	Expiration Date	Capacity	Borrowings	Letters of		
				Credit	Total	Available
				Issued	Used	Capacity
(In millions)						
Hess Corporation						
Revolving credit facility	May 2023	\$ 3,500	\$ —	\$ —	\$ —	\$ 3,500
Committed lines	Various (a)	175	—	54	54	121
Uncommitted lines	Various (a)	215	—	215	215	—
Total - Hess Corporation		<u>\$ 3,890</u>	<u>\$ —</u>	<u>\$ 269</u>	<u>\$ 269</u>	<u>\$ 3,621</u>
Midstream						
Revolving credit facility (b)	December 2024	\$ 1,000	\$ 184	\$ —	\$ 184	\$ 816
Total - Midstream		<u>\$ 1,000</u>	<u>\$ 184</u>	<u>\$ —</u>	<u>\$ 184</u>	<u>\$ 816</u>

(a) Committed and uncommitted lines have expiration dates through 2021.

(b) This credit facility may only be utilized by HESM Opco and is non-recourse to Hess Corporation.

Hess Corporation:

In 2020, we entered into a \$1 billion three year term loan agreement with a maturity date of March 16, 2023. Borrowings under the term loan generally bear interest at LIBOR plus an applicable margin of 2.25% until the term loan's first anniversary. The applicable margin varies based on the credit rating of the Corporation's senior unsecured long-term debt and will increase by 0.25% on each anniversary of the term loan.

In 2019, we entered into a new \$3.5 billion revolving credit facility with a maturity date of May 15, 2023, which replaced the Corporation's previous revolving credit facility. The new facility can be used for borrowings and letters of credit. Borrowings will generally bear interest at 1.30% above LIBOR, though the interest rate is subject to adjustment if the Corporation's credit rating changes. At December 31, 2020, Hess Corporation had no outstanding borrowings or letters of credit under this facility.

The revolving credit facility and term loan are subject to customary representations, warranties, customary events of default and covenants, including a financial covenant limiting the ratio of Total Consolidated Debt to Total Capitalization of the Corporation and its consolidated subsidiaries to 65%, and a financial covenant limiting the ratio of secured debt to Consolidated Net Tangible Assets of

the Corporation and its consolidated subsidiaries to 15% (as these capitalized terms are defined in the credit agreement for the revolving credit facility and the term loan agreement). The indentures for the Corporation's fixed-rate public notes limit the ratio of secured debt to Consolidated Net Tangible Assets (as that term is defined in the indentures) to 15%. As of December 31, 2020, Hess Corporation was in compliance with these financial covenants. For additional information regarding the alteration or discontinuation of LIBOR on our borrowing costs, see *Financial Risks* in *Item 1A. Risk Factors*.

The most restrictive of the financial covenants related to our fixed-rate public notes and our term loan and revolving credit facility would allow us to borrow up to an additional \$1,730 million of secured debt at December 31, 2020.

We had \$269 million in letters of credit outstanding at December 31, 2020 (2019: \$272 million), which primarily relate to our international operations. We have a shelf registration under which we may issue additional debt securities, warrants, common stock or preferred stock.

Midstream:

At December 31, 2020, Hess Midstream Operations LP (formerly Hess Midstream Partners LP, or HESM Opco), a consolidated subsidiary of Hess Midstream LP, had \$1.4 billion of senior secured syndicated credit facilities maturing December 16, 2024, consisting of a \$1.0 billion five year

revolving credit facility and a fully drawn \$400 million five year term loan A facility. The revolving credit facility can be used for borrowings and letters of credit to fund HESM Opco's operating activities, capital expenditures, distributions and for other general corporate purposes. Borrowings under the five year term loan A facility will generally bear interest at LIBOR plus an applicable margin ranging from 1.55% to 2.50%, while the applicable margin for the five year syndicated revolving credit facility ranges from 1.275% to 2.000%. Pricing levels for the facility fee and interest-rate margins are based on HESM Opco's ratio of total debt to EBITDA (as defined in the credit facilities). If HESM Opco obtains an investment grade credit rating, the pricing levels will be based on HESM Opco's credit ratings in effect from time to time. The credit facilities contain covenants that require HESM Opco to maintain a ratio of total debt to EBITDA (as defined in the credit facilities) for the prior four fiscal quarters of not greater than 5.00 to 1.00 as of the last day of each fiscal quarter (5.50 to 1.00 during the specified period following certain acquisitions) and, prior to HESM Opco obtaining an investment grade credit rating, a ratio of secured debt to EBITDA for the prior four fiscal quarters of not greater than 4.00 to 1.00 as of the last day of each fiscal quarter. HESM Opco was in compliance with these financial covenants at December 31, 2020. The credit facilities are secured by first-priority perfected liens on substantially all the presently owned and after-acquired assets of HESM Opco and its direct and indirect wholly owned material domestic subsidiaries, including equity interests directly owned by such entities, subject to certain customary exclusions. At December 31, 2020, borrowings of \$184 million were drawn under HESM Opco's revolving credit facility, and borrowings of \$400 million, excluding deferred issuance costs, were drawn under HESM Opco's term loan A facility. Borrowings under these credit facilities are non-recourse to Hess Corporation.

Credit Ratings

Two of the three major credit rating agencies that rate our debt have assigned an investment grade rating. Standard and Poor's Ratings Services affirmed our credit rating at BBB- with negative outlook in October 2020 while Fitch Ratings affirmed a BBB- credit rating and stable outlook in August 2020. Moody's Investors Service affirmed our credit rating at Ba1 with stable outlook, which is below investment grade, in March 2020.

At December 31, 2020, HESM Opco's senior unsecured debt is rated BB+ by Standard and Poor's Ratings Services and Fitch Ratings, and Ba3 by Moody's Investors Service.

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Contractual Obligations and Contingencies

The following table sets forth aggregate information about certain of the Corporation's consolidated contractual obligations at December 31, 2020:

	Total	Payments Due by Period			
		2022 and 2021	2023	2024 and 2025	Thereafter
		(In millions)			
Total Debt (excluding deferred financing costs, discounts, and interest) (a)	\$ 8,372	\$ 10	\$ 1,050	\$ 824	\$ 6,488
Finance Leases (b)	356	36	72	72	176
Operating Leases (b)	663	83	155	138	287
Purchase Obligations:					
Capital expenditures (b)	2,837	868	1,469	500	—
Operating expenses (b)	236	167	63	5	1
Transportation and related contracts (b)	2,867	310	756	493	1,308
Asset retirement obligations	2,116	105	170	86	1,755
Other liabilities	583	79	95	75	334

(a) We anticipate cash payments for interest on Total Debt of \$440 million for 2021, \$850 million for 2022-2023, \$784 million for 2024-2025, and \$3,231 million thereafter for a total of \$5,305 million. These interest payments reflect our contractual obligations at December 31, 2020.

(b) Comprises obligations, including where we, as operator, have contracted directly with suppliers.

Capital expenditures represent amounts for which we were contractually committed at December 31, 2020, and include a portion of our planned capital expenditure program for 2021. Obligations for operating expenses include commitments for oil and gas production expenses, seismic purchases and other normal business expenses. Other liabilities reflect contractually committed obligations in the *Consolidated Balance Sheet* at December 31, 2020, including post-retirement plan liabilities for our unfunded plans and estimates for uncertain income tax positions. The Corporation and certain of its subsidiaries primarily lease drilling rigs, equipment, logistical assets (offshore vessels, aircraft, and shorebases), and office space for varying periods. See Note 6, *Leases* in the *Notes to Consolidated Financial Statements*.

Off-Balance Sheet Arrangements

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At December 31, 2020, we had \$269 million in letters of credit. See also *Note 18, Guarantees, Contingencies and Commitments* in the *Notes to Consolidated Financial Statements*.

Foreign Operations

We conduct E&P activities outside the U.S., principally in Guyana, the Joint Development Area of Malaysia/Thailand, Malaysia, Denmark, Libya, Suriname, and Canada. Therefore, we are subject to the risks associated with foreign operations, including political risk, tax law changes, currency risk, corruption and acts of terrorism. See *Item 1A. Risk Factors* for further details.

Critical Accounting Policies and Estimates

Accounting policies and estimates affect the recognition of assets and liabilities in the *Consolidated Balance Sheet* and revenues and expenses in the *Statement of Consolidated Income*. The accounting methods used can affect net income, equity and various financial statement ratios. However, our accounting policies generally do not change cash flows or liquidity.

Accounting for Exploration and Development Costs: E&P activities are accounted for using the successful efforts method. Costs of acquiring unproved and proved oil and gas leasehold acreage, including lease bonuses, brokers' fees and other related costs are capitalized. Annual lease rentals, exploration expenses and exploratory dry hole costs are expensed as incurred. Costs of drilling and equipping productive wells, including development dry holes, and related production facilities are capitalized.

The costs of exploratory wells that find oil and gas reserves are capitalized pending determination of whether proved reserves have been found. Exploratory drilling costs remain capitalized after drilling is completed if (1) the well has found a sufficient quantity of reserves to justify completion as a producing well and (2) sufficient progress is being made in assessing the reserves and the economic and operational viability of the project. If either of those criteria is not met, or if there is substantial doubt about the economic or operational viability of the project, the capitalized well costs are charged to expense. Indicators of sufficient progress in assessing reserves, and the economic and operating viability of a project include: commitment of project personnel, active negotiations for sales contracts with customers, negotiations with governments, operators and contractors and firm plans for additional drilling and other factors.

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Crude Oil and Natural Gas Reserves: The determination of estimated proved reserves is a significant element in arriving at the results of operations of E&P activities. The estimates of proved reserves affect well capitalizations, the unit of production depreciation rates of proved properties and wells and equipment, as well as impairment testing of oil and gas assets.

For reserves to be booked as proved they must be determined with reasonable certainty to be economically producible from known reservoirs under existing economic conditions, operating methods and government regulations. In addition, government and project operator approvals must be obtained and, depending on the amount of the project cost, senior management or the Board of Directors must commit to fund the project. We maintain our own internal reserve estimates that are calculated by technical staff that work directly with the oil and gas properties. Our technical staff update reserve estimates throughout the year based on evaluations of new wells, performance reviews, new technical data and other studies. To provide consistency throughout the Corporation, standard reserve estimation guidelines, definitions, reporting reviews and approval practices are used. The internal reserve estimates are subject to internal technical audits and senior management review. We also engage an independent third-party consulting firm to audit approximately 80% of our total proved reserves each year.

Proved reserves are calculated using the average price during the twelve-month period ending December 31 determined as an unweighted arithmetic average of the price on the first day of each month within the year, unless prices are defined by contractual agreements, excluding escalations based on future conditions. As discussed in *Item 1A. Risk Factors*, crude oil prices are volatile which can have an impact on our proved reserves. If crude oil prices in 2021 are at levels below that used in determining 2020 proved reserves, we may recognize negative revisions to our December 31, 2021 proved undeveloped reserves. In addition, we may recognize negative revisions to proved developed reserves, which can vary significantly by asset due to differing operating cost structures. Conversely, price increases in 2021 above those used in determining 2020 proved reserves could result in positive revisions to proved developed and proved undeveloped reserves at December 31, 2021. It is difficult to estimate the magnitude of any potential net negative or positive change in proved reserves at December 31, 2021, due to numerous currently unknown factors, including 2021 crude oil prices, the amount of any additions to proved reserves, positive or negative revisions in proved reserves related to 2021 reservoir performance, the levels to which industry costs will change in response to 2021 crude oil prices, and management's plans as of December 31, 2021 for developing proved undeveloped reserves. A 10% change in proved developed and proved undeveloped reserves at December 31, 2020 would result in an approximate \$150 million pre-tax change in depreciation, depletion, and amortization expense for 2021 based on projected production volumes. See the *Supplementary Oil and Gas Data* on pages 91 through 99 in the accompanying financial statements for additional information on our oil and gas reserves.

Impairment of Long-lived Assets: We review long-lived assets, including oil and gas fields, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. Long-lived assets are tested based on identifiable cash flows that are largely independent of the cash flows of other assets and liabilities. If the carrying amounts of the long-lived assets are not expected to be recovered by estimated undiscounted future net cash flows, the assets are impaired and an impairment loss is recorded. The amount of impairment is measured based on the estimated fair value of the assets generally determined by discounting anticipated future net cash flows, an income valuation approach, or by a market-based valuation approach, which are Level 3 fair value measurements.

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In the case of oil and gas fields, the present value of future net cash flows is based on management's best estimate of future prices, which is determined with reference to recent historical prices and published forward prices, applied to projected production volumes and discounted at a risk-adjusted rate. The projected production volumes represent reserves, including probable reserves, expected to be produced based on a stipulated amount of capital expenditures. The production volumes, prices and timing of production are consistent with internal projections and other externally reported information. Oil and gas prices used for determining asset impairment will generally differ from those used in the standardized measure of discounted future net cash flows, since the standardized measure requires the use of historical twelve-month average prices.

Our impairment tests of long-lived E&P producing assets are based on our best estimates of future production volumes (including recovery factors), selling prices, operating and capital costs, the timing of future production and other factors, which are updated each time an impairment test is performed. As a result of the significant decline in crude oil prices due to the economic slowdown from the COVID-19 pandemic, we reviewed our oil and gas fields and midstream operating segment asset groups for impairment at March 31, 2020. We impaired various oil and gas fields located in Malaysia, Denmark, and the Gulf of Mexico in the first quarter of 2020 primarily as a result of a lower long-term crude oil price outlook. See *Note 12, Impairment* in the *Notes to Consolidated Financial Statements* for further details. We could experience an impairment in the future if one or a combination of the following occur: the projected production volumes from oil and gas fields decrease, crude oil and natural gas selling prices decline below the long-term crude oil price outlook used in the March 31, 2020 impairment test, or future estimated capital and operating costs increase significantly.

Hess Midstream LP: We consolidate the activities of our interest in Hess Midstream LP, which qualifies as a variable interest entity (VIE) under U.S. generally accepted accounting principles. We have concluded that we are the primary beneficiary of the VIE, as defined in the accounting standards, since we have the power through Hess Corporation's 47% consolidated ownership interest in Hess Midstream LP to direct those activities that most significantly impact the economic performance of Hess Midstream LP, and are obligated to absorb losses or have the right to receive benefits that could potentially be significant to Hess Midstream LP. This

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conclusion was based on a qualitative analysis that considered Hess Midstream LP's governance structure, the commercial agreements between Hess Midstream LP and us, and the voting rights established between the members, which provide us the ability to control the operations of Hess Midstream LP.

Income Taxes: Judgments are required in the determination and recognition of income tax assets and liabilities in the financial statements. These judgments include the requirement to recognize the financial statement effect of a tax position only when management believes it is more likely than not, based on the technical merits, that the position will be sustained upon examination.

We have net operating loss carryforwards or credit carryforwards in multiple jurisdictions and have recorded deferred tax assets for those losses and credits. Additionally, we have deferred tax assets due to temporary differences between the book basis and tax basis of certain assets and liabilities. Regular assessments are made as to the likelihood of those deferred tax assets being realized. If, when tested under the relevant accounting standards, it is more likely than not that some or all of the deferred tax assets will not be realized, a valuation allowance is recorded to reduce the deferred tax assets to the amount that is expected to be realized.

The accounting standards require the evaluation of all available positive and negative evidence giving weight based on the evidence's relative objectivity. In evaluating potential sources of positive evidence, we consider the reversal of taxable temporary differences, taxable income in carryback and carryforward periods, the availability of tax planning strategies, the existence of appreciated assets, estimates of future taxable income, and other factors. Estimates of future taxable income are based on assumptions of oil and gas reserves, selling prices, and other subjective operating assumptions that are consistent with internal business forecasts. In evaluating potential sources of negative evidence, we consider a cumulative loss in recent years, any history of operating losses or tax credit carryforwards expiring unused, losses expected in early future years, unsettled circumstances that, if unfavorably resolved, would adversely affect future operations and profit levels on a continuing basis in future years, and any carryback or carryforward period so brief that a significant deductible temporary difference expected to reverse in a single year would limit realization of tax benefits. Due to a sustained low commodity price environment, we remained in a three-year cumulative consolidated loss position at December 31, 2020. A three-year cumulative consolidated loss constitutes objective negative evidence to which the accounting standards require we assign significant weight relative to subjective evidence such as our estimates of future taxable income. We are generally not recognizing deferred tax benefit or expense in certain countries, primarily the U.S., Denmark, and Malaysia, while we maintain valuation allowances against net deferred tax assets in these jurisdictions. In December 2019, we reversed the valuation allowance of \$60 million for Guyana upon achieving first production from the Liza Phase 1 development.

At December 31, 2020, the *Consolidated Balance Sheet* reflects a \$5,391 million valuation allowance against the net deferred tax assets for multiple jurisdictions based on the evaluation of the accounting standards described above. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income change or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as expected future growth.

Asset Retirement Obligations: We have material legal obligations to remove and dismantle long-lived assets and to restore land or seabed at certain E&P locations. In accordance with generally accepted accounting principles, we recognize a liability for the fair value of required asset retirement obligations. In addition, the fair value of any legally required conditional asset retirement obligation is recorded if the liability can be

reasonably estimated. We capitalize such costs as a component of the carrying amount of the underlying assets in the period in which the liability is incurred. In subsequent periods, the liability is accreted, and the asset is depreciated over the useful life of the related asset. We estimate the fair value of these obligations by discounting projected future payments that will be required to satisfy the obligations. In determining these estimates, we are required to make several assumptions and judgments related to the scope of dismantlement, timing of settlement, interpretation of legal requirements, inflationary factors and discount rate. In addition, there are other external factors, which could significantly affect the ultimate settlement costs or timing for these obligations including changes in environmental regulations and other statutory requirements, fluctuations in industry costs and foreign currency exchange rates and advances in technology. As a result, our estimates of asset retirement obligations are subject to revision due to the factors described above. Changes in estimates prior to settlement result in adjustments to both the liability and related asset values, unless the field has ceased production, in which case changes are recognized in our *Consolidated Statement of Income*. See *Note 8, Asset Retirement Obligations*.

Retirement Plans: We have funded non-contributory defined benefit pension plans, an unfunded supplemental pension plan and an unfunded postretirement medical plan. We recognize the net change in the funded status of the projected benefit obligation for these plans in the *Consolidated Balance Sheet*. The determination of the obligations and expenses related to these plans are based on several actuarial assumptions. These assumptions represent estimates made by us, some of which can be affected by external factors. The most significant assumptions relate to:

Discount rates used for measuring the present value of future plan obligations and net periodic benefit cost: The discount rates used to estimate our projected benefit obligations and net periodic benefit cost is based on a portfolio of high-quality, fixed income debt instruments with maturities that approximate the expected payment of plan obligations. At December 31, 2020, a 0.25% decrease in the discount rate assumptions would increase projected benefit obligations by approximately \$145 million and would decrease forecasted 2021 annual net periodic benefit income by approximately \$10 million. The increase in the projected benefit obligations

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would decrease the funded status of our pension plans, but any decrease in the funded status would be partially mitigated by increases in the fair value of fixed income investments in the asset portfolios.

Expected long-term rates of returns on plan assets: The expected return on plan assets is developed from the expected future returns for each asset category, weighted by the target allocation of plan assets to that asset category. The future expected return assumptions for individual asset categories are largely based on inputs from various investment experts regarding their future return expectations for particular asset categories. At December 31, 2020, a 0.25% decrease in the expected long-term rates of return on plan assets assumption would decrease forecasted 2021 annual net periodic benefit income by approximately \$10 million.

Other assumptions include the rate of future increases in compensation levels and expected participant mortality.

Derivatives: We utilize derivative instruments, including futures, forwards, options and swaps, individually or in combination to mitigate our exposure to fluctuations in the prices of crude oil and natural gas, as well as changes in interest and foreign currency exchange rates. All derivative instruments are recorded at fair value in our *Consolidated Balance Sheet*. Our policy for recognizing the changes in fair value of derivatives varies based on the designation of the derivative. The changes in fair value of derivatives that are not designated as hedges are recognized currently in earnings. Derivatives may be designated as hedges of expected future cash flows or forecasted transactions (cash flow hedges), or hedges of changes in fair value of recognized assets and liabilities or of unrecognized firm commitments (fair value hedges). Changes in fair value of derivatives that are designated as cash flow hedges are recorded as a component of other comprehensive income (loss). Amounts included in Accumulated other comprehensive income (loss) for cash flow hedges are reclassified into earnings in the same period that the hedged item is recognized in earnings. Changes in fair value of derivatives designated as fair value hedges are recognized currently in earnings. The change in fair value of the related hedged item is recorded as an adjustment to its carrying amount and recognized currently in earnings.

Fair Value Measurements: We use various valuation approaches in determining fair value for financial instruments, including the market and income approaches. Our fair value measurements also include non-performance risk and time value of money considerations. Counterparty credit is considered for receivable balances, and our credit is considered for accrued liabilities.

We also record certain nonfinancial assets and liabilities at fair value when required by generally accepted accounting principles. These fair value measurements are recorded in connection with business combinations, qualifying non-monetary exchanges, the initial recognition of asset retirement obligations and any impairment of long-lived assets, equity method investments or goodwill.

We determine fair value in accordance with the fair value measurements accounting standard which established a hierarchy for the inputs used to measure fair value based on the source of the inputs, which generally range from quoted prices for identical instruments in a principal trading market (Level 1) to estimates determined using related market data (Level 3), including discounted cash flows and other unobservable data. Measurements derived indirectly from observable inputs or from quoted prices from markets that are less liquid are considered Level 2. When Level 1 inputs are available within a particular market, those inputs are selected for determination of fair value over Level 2 or 3 inputs in the same market. Multiple inputs may be used to measure fair value; however, the level assigned to a fair value measurement is based on the lowest significant input level within this fair value hierarchy.

Environment, Health and Safety

Our long-term vision and values provide a foundation for how we do business and define our commitment to meeting high standards of corporate citizenship and creating a long lasting positive impact on the communities where we do business. Our strategy is reflected in our EHS & SR policies and by a management system framework that helps protect our workforce, customers and local communities. Our management systems are intended to promote internal consistency, adherence to policy objectives and continual improvement in EHS & SR performance. Improved performance may, in the short-term, increase our operating costs and could also require increased capital expenditures to reduce potential risks to our assets, reputation and license to operate. In addition to enhanced EHS & SR performance, improved productivity and operational efficiencies may be realized from investments in EHS & SR. We have programs in place to evaluate regulatory compliance, audit facilities, train employees, prevent and manage risks and emergencies and to generally meet corporate EHS & SR goals and objectives.

Environmental Matters

We recognize that climate change is a global environmental concern. We assess, monitor and take measures to reduce our carbon footprint at existing and planned operations. The EPA has adopted a series of GHG monitoring, reporting, and emissions control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting further legislation to reduce GHG emissions. In addition, states have taken measures to reduce emissions of GHGs, primarily through the development of GHG emission inventories and/or regional GHG cap-and-trade programs. At the international level, the Paris Agreement on climate change aimed to enhance global response to global temperature changes and to reduce GHG emissions, among other things. We are committed to complying with all GHG emissions regulations that apply to our operations, including those related to venting or flaring of natural gas, and the responsible management of GHG emissions at our facilities. While we monitor climate-related regulatory initiatives and international public policy issues, the current state of ongoing international climate initiatives and any related domestic

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actions make it difficult to assess the timing or effect on our operations or to predict with certainty the future costs that we may incur in order to comply with future international treaties, legislation or new regulations. However, future restrictions on emissions of GHGs, or related measures to encourage use of low carbon energy could result in higher capital expenditures and operating expenses for us and the oil and gas industry in general and may reduce demand for our products, as described under *Regulatory, Legal and Environmental Risks* in *Item 1A. Risk Factors*.

We will have continuing expenditures for environmental assessment and remediation. Sites where corrective action may be necessary include E&P facilities, sites from discontinued operations where we retained liability and, although not currently significant, EPA “Superfund” sites where we have been named a potentially responsible party. We accrue for environmental assessment and remediation expenses when the future costs are probable and reasonably estimable. For additional information, see *Item 3. Legal Proceedings*. At December 31, 2020, our reserve for estimated remediation liabilities was approximately \$65 million. We expect that existing reserves for environmental liabilities will adequately cover costs to assess and remediate known sites. Our remediation spending was approximately \$15 million in 2020 (2019: \$20 million; 2018: \$15 million). The amount of other expenditures incurred to comply with federal, state, local and foreign country environmental regulations is difficult to quantify as such costs are captured as mostly indistinguishable components of our capital expenditures and operating expenses.

Health and Safety Matters

The crude oil and natural gas industry is regulated at federal, state, local and foreign government levels regarding the health and safety of E&P operations. Such laws and regulations relate to, among other matters, occupational safety, the use of hydraulic fracturing to stimulate crude oil and natural gas production, well control and integrity, process safety and equipment integrity, and may include permitting and disclosure requirements, operating restrictions and other conditions on the development of crude oil and natural gas. The level of our expenditures to comply with federal, state, local and foreign country health and safety regulations is difficult to quantify as such costs are captured as mostly indistinguishable components of our capital expenditures and operating expenses. While compliance with laws and regulations relating to health and safety matters increases the overall cost of business for us and the oil and gas industry in general, it has not had, to date, a material adverse effect on our operations, financial condition or results of operations.

Occupational Safety: We are subject to the requirements set forth under federal workplace standards by the OSHA and comparable state statutes that regulate the protection of the health and safety of workers. Under OSHA and other federal and state occupational safety and health laws and laws of foreign countries in which we operate, we must develop, maintain and disclose certain information about hazardous materials used, released, or produced in our operations.

Production and Well Integrity: Our U.S. onshore production facilities are subject to U.S. federal government, state and local regulations regarding the use of hydraulic fracturing and well control and integrity. Our offshore production facilities in the Gulf of Mexico are subject to the U.S. federal government’s Safety and Environmental Management System regulations, which provide a systematic approach for identifying, managing and mitigating hazards. Adapting to new technical standards and procedures in production and in our well integrity management system is fundamental to our aim of protecting the environment as well as the health and safety of our workforce and the communities in which we operate, and to safeguarding our product.

Process Safety and Equipment Integrity: We are also regulated at federal, state, local and foreign government levels regarding process safety and the integrity of our equipment, including OSHA’s Process Safety Management of Highly Hazardous Chemicals standard. ICE are barriers and

safeguards that prevent or mitigate process safety incidents through detection, isolation, containment, control or emergency preparedness and response within our facilities. We have established ICE performance standards, which set specific requirements and criteria for inspections and tests that help to ensure ICE barriers are effective. We conduct assessments collaboratively with our operated assets, subject matter experts and technical authorities to evaluate compliance with corporate and asset environment, health and safety standards and procedures, as well as with applicable regulations. For additional information on our emergency response and incident mitigation activities, see *Emergency Preparedness and Response Plans and Procedures in Items 1 and 2. Business and Properties*.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

In the normal course of our business, we are exposed to commodity risks related to changes in the prices of crude oil, NGL, and natural gas as well as changes in interest rates and foreign currency values. In the disclosures that follow, financial risk management activities refer to the mitigation of these risks through hedging activities.

Controls: We maintain a control environment under the direction of our Chief Risk Officer. Controls over instruments used in financial risk management activities include volumetric and term limits. Our Treasury department is responsible for administering and monitoring foreign exchange rate and interest rate hedging programs using similar controls and processes, where applicable. Hedging strategies are reviewed annually by the Audit Committee of the Board of Directors.

Instruments: We primarily use forward commodity contracts, foreign exchange forward contracts, futures, swaps, and options in our risk management activities. These contracts are generally widely traded instruments with standardized terms. The following describes these instruments and how we use them:

- **Swaps:** We use financially settled swap contracts with third parties as part of our financial risk management activities. Cash flows from swap contracts are determined based on underlying commodity prices or interest rates and are typically settled over the life of the contract.
- **Forward Foreign Exchange Contracts:** We enter into forward contracts, primarily for the British Pound, Danish Krone, Canadian Dollar and Malaysian Ringgit, which commit us to buy or sell a fixed amount of those currencies at a predetermined exchange rate on a future date.
- **Exchange-traded Contracts:** We may use exchange-traded contracts, including futures, on a number of different underlying energy commodities. These contracts are settled daily with the relevant exchange and may be subject to exchange position limits.
- **Options:** Options on various underlying energy commodities include exchange-traded and third-party contracts and have various exercise periods. As a seller of options, we receive a premium at the outset and bear the risk of unfavorable changes in the price of the commodity underlying the option. As a purchaser of options, we pay a premium at the outset and have the right to participate in the favorable price movements in the underlying commodities.

Financial Risk Management Activities

We have outstanding foreign exchange contracts with notional amounts totaling \$163 million at December 31, 2020 that are used to reduce our exposure to fluctuating foreign exchange rates for various currencies. The change in fair value of foreign exchange contracts from a 10% strengthening or weakening in the U.S. Dollar exchange rate is estimated to be a gain or loss of less than \$5 million, respectively, at December 31, 2020.

At December 31, 2020, our total long-term debt, which was substantially comprised of fixed-rate instruments, had a carrying value of \$8,296 million and a fair value of \$9,647 million. A 15% increase or decrease in interest rates would decrease or increase the fair value of debt by approximately \$400 million or \$430 million, respectively. Any changes in interest rates do not impact our cash outflows associated with fixed-rate interest payments or settlement of debt principal, unless a debt instrument is repurchased prior to maturity.

At December 31, 2020, we had WTI put options with an average monthly floor price of approximately \$45 per barrel for 75,000 bopd for 2021. As of December 31, 2020, an assumed 10% increase in the forward WTI crude oil prices used in determining the fair value of our WTI put options would reduce the fair value of these derivative instruments by approximately \$20 million, while an assumed 10% decrease in the same crude oil prices would increase the fair value of these derivative instruments by approximately \$30 million. In the first quarter of 2021, we increased the average monthly floor price of 75,000 bopd of WTI put option contracts from approximately \$45 per barrel to \$50 per barrel for the remainder of 2021. We also purchased additional WTI put options with an average monthly floor price of \$50 per barrel for 45,000 bopd and Brent put options with an average monthly floor price of \$55 per barrel for 30,000 bopd. As a result, we now have total purchased WTI put options of 120,000 bopd with an average monthly floor price of \$50 per barrel and total purchased Brent put options of 30,000 bopd with an average monthly floor price of \$55 per barrel for the remainder of 2021.

We have outstanding Brent crude oil swap contracts associated with the 4.2 million barrels stored on two VLCCs at year-end. As of December 31, 2020, an assumed 10% increase in the forward Brent crude oil prices used in determining the fair value of our Brent swaps would reduce the fair value of these derivative instruments by approximately \$20 million, while an assumed 10% decrease in the same crude oil prices would increase the fair value of these derivative instruments by approximately \$20 million.

See Note 20, *Financial Risk Management Activities* in the *Notes to Consolidated Financial Statements* for further details.

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Item 8. Financial Statements and Supplementary Data

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES INDEX TO FINANCIAL STATEMENTS

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Schedules have been omitted because of the absence of the conditions under which they are required or because the required information is presented in the financial statements or the notes thereto.

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Management's Report on Internal Control over Financial Reporting

FWE-0040121

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2020.

The Corporation's independent registered public accounting firm, Ernst & Young LLP, has audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2020, as stated in their report, which is included herein.

By <u>/s/ John P. Rielly</u> John P. Rielly	By <u>/s/ John B. Hess</u>
Executive Vice President and Chief Financial Officer	John B. Hess Chief Executive Officer

March 1, 2021

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders Hess Corporation

Opinion on Internal Control over Financial Reporting

We have audited Hess Corporation and consolidated subsidiaries' (the "Corporation") internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Hess Corporation and consolidated subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Corporation as of December 31, 2020 and 2019, the related statements of consolidated income, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2020, and the related notes and our report dated March 1, 2021 expressed an unqualified opinion thereon.

Basis for Opinion

The Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Corporation's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Corporation in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting

principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young LLP
New York, New York
March 1, 2021

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders Hess Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Hess Corporation and consolidated subsidiaries (the "Corporation") as of December 31, 2020 and 2019, the related statements of consolidated income, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2020, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the consolidated financial position of the Corporation at December 31, 2020 and 2019, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Corporation's internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated March 1, 2021 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the Corporation's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Corporation in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission (SEC) and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Depreciation, depletion and amortization of proved oil and natural gas properties*Description of the Matter*

The net book value of the Corporation's exploration and production assets was \$10,993 million at December 31, 2020, and depreciation, depletion and amortization (DD&A) expense was \$1,915 million for the year then ended. As described in Note 1 to the financial statements, the Corporation follows the successful efforts method of accounting for its oil and gas exploration and production activities. Under the successful efforts method of accounting, DD&A expense is recorded using the units-of-production method, based on proved oil and gas reserves, as estimated by petroleum engineering specialists, for property acquisition costs and proved developed oil and gas reserves, also estimated by petroleum engineering specialists, for oil and gas production facilities and wells. Proved oil and gas reserves are based on geological and engineering evaluations of

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estimated in-place hydrocarbon volumes using financial and non-financial inputs. Significant judgment is required by the Corporations' internal engineering staff in evaluating the geological and engineering data used to estimate reserves. Estimating proved reserves also requires the selection of inputs, including oil and natural gas price assumptions, future operating and capital costs assumptions and tax rates by jurisdiction, among others. Management used independent petroleum engineering specialists to audit approximately 92% of the Corporation's proved reserves at December 31, 2020 as prepared by the Corporation's internal engineering staff.

Auditing the Corporation's DD&A expense calculation is complex because of our need to assess the reasonableness of management's determination of the inputs described above used in estimating proved oil and gas reserves and to use the work of the internal engineering staff and independent petroleum engineering specialists.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design and tested the operating effectiveness of internal controls that address the risks of material misstatement relating to the DD&A expense calculation. This included controls over the completeness and accuracy of the financial data used in estimating proved oil and gas reserves.

Our testing of the Corporation's DD&A expense calculation included, among other procedures, evaluating the professional qualifications and objectivity of the Corporation's internal petroleum engineering specialist responsible for overseeing the preparation of the Corporation's reserve estimates and of the independent petroleum engineering specialist used to audit the estimates. In addition, we tested the completeness and accuracy of the financial data used in the estimation of proved oil and gas reserves by agreeing significant inputs to source documentation, where available, on a sample basis and assessing the inputs for reasonableness based on review of corroborative evidence and consideration of any contrary evidence. For proved undeveloped reserves, we evaluated management's development plans for compliance with the SEC rule that undrilled locations are scheduled to be drilled within five years, unless specific circumstances justify a longer time, by assessing consistency of the development projection with the Corporation's drill plan and the availability of capital relative to the drill plan. Additionally, we performed analytic and lookback procedures on inputs into the oil and gas reserve estimate as well as on the outputs. Finally, we tested the mathematical accuracy of the DD&A expense calculations, including comparing the proved oil and gas reserves to the Corporation's reserve report.

Impairment of oil and natural gas properties*Description of the**Matter*

The net book value of the Corporation's exploration and production assets was \$10,993 million at December 31, 2020, and impairment expense was \$2,105 million for the year then ended. As described in Notes 1 and 12 to the financial statements, the Corporation reviews long-lived assets, including oil and gas fields, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts of the long-lived assets are not expected to be recovered by estimated undiscounted future net cash flows, the assets are impaired, and an impairment loss is recorded. The impairments recorded in 2020 were based on estimates of fair value determined by discounting internally developed future net cash flows, a

Level 3 fair value measurement. Significant inputs used in determining the discounted future net cash flows include future prices, which are determined with reference to recent historical prices and published forward prices, projected production volumes using risk adjusted oil and gas reserves and discount rates. The projected production volumes are based on geological

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and engineering evaluations of estimated in-place hydrocarbon volumes using financial and non-financial inputs including projected capital expenditures. Significant judgment is required by the Corporations' internal petroleum engineering staff in evaluating the geological and engineering data used to estimate reserves. Estimating projected production volumes also requires the selection of inputs, including oil and natural gas price assumptions, future operating and capital costs assumptions and tax rates by jurisdiction, among others.

Auditing the Corporation's impairment calculation involved a high degree of subjectivity as the determination of fair value was based on assumptions as described above about future market and economic conditions. In addition, the cash flows include projected production volumes based on risk adjusted reserve estimates developed by the Corporation's internal engineering staff.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design and tested the operating effectiveness of internal controls that address the risks of material misstatement relating to the impairment expense calculation. This included controls over the completeness and accuracy of the significant inputs used to estimate fair value including pricing assumptions and projected production volumes among others.

Our testing of the Corporation's impairment calculation included, among other procedures, evaluating the significant assumptions used and testing the completeness and accuracy of the underlying data. We involved our valuation specialists to assist in evaluating the appropriateness of the methodology used in the cash flow model, as well as certain of the inputs, including reserve risk adjustment factors and projected pricing among other market inputs. We additionally evaluated the professional qualifications and objectivity of the Corporation's internal petroleum engineering specialist responsible for overseeing the preparation of the Corporation's reserve estimates and of the independent petroleum engineering specialist. We performed testing procedures including testing the completeness and accuracy of the financial data used in the estimation of oil and gas reserves by agreeing significant inputs to source documentation, where available, on a sample basis and assessing the inputs for reasonableness based on review of corroborative evidence and consideration of any contrary evidence. We also performed sensitivity analyses and a retrospective comparison of forecasted cash flows to actual historical data. Finally, we tested the mathematical accuracy of the impairment calculations.

/s/ Ernst & Young LLP
We have served as the Corporation's auditor since 1971
New York, New York

FWE-0040125

March 1, 2021

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HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED BALANCE SHEET

	December 31,	
	2020	2019
	(In millions, except share amounts)	
Assets		
Current Assets:		
Cash and cash equivalents	\$ 1,739	\$ 1,545
Accounts receivable:		
From contracts with customers	710	940
Joint venture and other	150	230
Inventories	378	261
Other current assets	104	180
Total current assets	<u>3,081</u>	<u>3,156</u>
Property, plant and equipment:		
Total — at cost	30,519	35,820
Less: Reserves for depreciation, depletion, amortization and lease impairment	16,404	19,006
Property, plant and equipment — net	<u>14,115</u>	<u>16,814</u>
Operating lease right-of-use assets — net	426	447
Finance lease right-of-use assets — net	168	299
Goodwill	360	360
Deferred income taxes	59	80
Other assets	612	626
Total Assets	<u><u>\$ 18,821</u></u>	<u><u>\$21,782</u></u>
Liabilities		
Current Liabilities:		
Accounts payable	\$ 200	\$ 411
Accrued liabilities	1,251	1,803
Taxes payable	81	97
Current maturities of long-term debt	10	—
Current portion of operating and finance lease obligations	81	199
Total current liabilities	<u>1,623</u>	<u>2,510</u>
Long-term debt	8,286	7,142
Long-term operating lease obligations	478	353
Long-term finance lease obligations	220	238
Deferred income taxes	342	415
Asset retirement obligations	894	897
Other liabilities and deferred credits	643	521
Total Liabilities	<u>12,486</u>	<u>12,076</u>
Equity		
Hess Corporation stockholders' equity:		
Common stock, par value \$1.00; Authorized — 600,000,000 shares:		
Issued — 306,980,092 shares (2019: 304,955,472)	307	305
Capital in excess of par value	5,684	5,591
Retained earnings	130	3,535
Accumulated other comprehensive income (loss)	(755)	(699)
Total Hess Corporation stockholders' equity	<u>5,366</u>	<u>8,732</u>
Noncontrolling interests	969	974
Total equity	<u>6,335</u>	<u>9,706</u>
Total Liabilities and Equity	<u><u>\$ 18,821</u></u>	<u><u>\$21,782</u></u>

The consolidated financial statements reflect the successful efforts method of accounting for oil and gas exploration and production activities.

See accompanying Notes to Consolidated Financial Statements.

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HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
STATEMENT OF CONSOLIDATED INCOME

	Year Ended December 31,		
	2020	2019	2018
	(In millions, except per share amounts)		
Revenues and Non-Operating Income			
Sales and other operating revenues	\$ 4,667	\$ 6,495	\$ 6,323
Gains on asset sales, net	87	22	32
Other, net	50	(7)	111
Total revenues and non-operating income	<u>4,804</u>	<u>6,510</u>	<u>6,466</u>
Costs and Expenses			
Marketing, including purchased oil and gas	936	1,736	1,771
Operating costs and expenses	1,218	1,237	1,134
Production and severance taxes	124	184	171
Exploration expenses, including dry holes and lease impairment	351	233	362
General and administrative expenses	357	397	473
Interest expense	468	380	399
Loss on debt extinguishment	—	—	53
Depreciation, depletion and amortization	2,074	2,122	1,883
Impairment	2,126	—	—
Total costs and expenses	<u>7,654</u>	<u>6,289</u>	<u>6,246</u>
Income (Loss) Before Income Taxes	<u>(2,850)</u>	<u>221</u>	<u>220</u>
Provision (benefit) for income taxes	(11)	461	335
Net Income (Loss)	<u>(2,839)</u>	<u>(240)</u>	<u>(115)</u>
Less: Net income (loss) attributable to noncontrolling interests	254	168	167
Net Income (Loss) Attributable to Hess Corporation	<u>(3,093)</u>	<u>(408)</u>	<u>(282)</u>
Less: Preferred stock dividends	—	4	46
Net Income (Loss) Attributable to Hess Corporation Common Stockholders	<u>\$ (3,093)</u>	<u>\$ (412)</u>	<u>\$ (328)</u>
Net Income (Loss) Attributable to Hess Corporation Per Common Share			
Basic	\$ (10.15)	\$ (1.37)	\$ (1.10)
Diluted	\$ (10.15)	\$ (1.37)	\$ (1.10)
Weighted Average Number of Common Shares Outstanding (Diluted)	304.8	301.2	298.2
Common Stock Dividends Per Share	\$ 1.00	\$ 1.00	\$ 1.00

See accompanying Notes to Consolidated Financial Statements.

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HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
STATEMENT OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2020	2019	2018
	(In millions)		
Net Income (Loss)	<u>\$ (2,839)</u>	<u>\$ (240)</u>	<u>\$ (115)</u>
Other Comprehensive Income (Loss):			
Derivatives designated as cash flow hedges			
Effect of hedge (gains) losses reclassified to income	(547)	(1)	173

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Income taxes on effect of hedge (gains) losses reclassified to income	—	—	—
Net effect of hedge (gains) losses reclassified to income	(547)	(1)	173
Change in fair value of cash flow hedges	649	(462)	330
Income taxes on change in fair value of cash flow hedges	—	86	(86)
Net change in fair value of cash flow hedges	649	(376)	244
Change in derivatives designated as cash flow hedges, after taxes	102	(377)	417
Pension and other postretirement plans			
(Increase) reduction in unrecognized actuarial losses	(205)	(160)	29
Income taxes on actuarial changes in plan liabilities	—	—	(6)
(Increase) reduction in unrecognized actuarial losses, net	(205)	(160)	23
Amortization of net actuarial losses	47	144	41
Income taxes on amortization of net actuarial losses	—	—	—
Net effect of amortization of net actuarial losses	47	144	41
Change in pension and other postretirement plans, after taxes	(158)	(16)	64
Other Comprehensive Income (Loss)	(56)	(393)	481
Comprehensive Income (Loss)	(2,895)	(633)	366
Less: Comprehensive income (loss) attributable to noncontrolling interests	254	168	167
Comprehensive Income (Loss) Attributable to Hess Corporation	\$ (3,149)	\$ (801)	\$ 199

See accompanying Notes to Consolidated Financial Statements.

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HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED CASH FLOWS

	Year Ended December 31,		
	2020	2019	2018
	(In millions)		
Cash Flows From Operating Activities			
Net income (loss)	\$ (2,839)	\$ (240)	\$ (115)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
(Gains) on asset sales, net	(87)	(22)	(32)
Depreciation, depletion and amortization	2,074	2,122	1,883
Impairment	2,126	—	—
Exploratory dry hole costs	192	49	165
Exploration lease and other impairment	51	17	37
Pension settlement loss	—	93	4
Stock compensation expense	79	85	72
Noncash (gains) losses on commodity derivatives, net	260	116	182
Provision (benefit) for deferred income taxes and other tax accruals	(53)	17	(120)
Loss on debt extinguishment	—	—	53
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	267	(383)	(138)
(Increase) decrease in inventories	(117)	(16)	(12)
Increase (decrease) in accounts payable and accrued liabilities	(533)	4	88
Increase (decrease) in taxes payable	(16)	16	(2)
Changes in other operating assets and liabilities	(71)	(216)	(126)
Net cash provided by (used in) operating activities	<u>1,333</u>	<u>1,642</u>	<u>1,939</u>
Cash Flows From Investing Activities			
Additions to property, plant and equipment - E&P	(1,896)	(2,433)	(1,854)
Additions to property, plant and equipment - Midstream	(301)	(396)	(243)
Payments for Midstream equity investments	—	(33)	(67)
Proceeds from asset sales, net of cash sold	493	22	607
Other, net	(3)	(3)	(9)
Net cash provided by (used in) investing activities	<u>(1,707)</u>	<u>(2,843)</u>	<u>(1,566)</u>
Cash Flows From Financing Activities			

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Net borrowings (repayments) of debt with maturities of 90 days or less	152	32	—
Debt with maturities of greater than 90 days:			
Borrowings	1,000	760	—
Repayments	—	(8)	(633)
Payments on finance lease obligations	(7)	(49)	—
Common stock acquired and retired	—	(25)	(1,365)
Cash dividends paid	(309)	(316)	(345)
Noncontrolling interests, net	(261)	(353)	(211)
Other, net	(7)	11	28
Net cash provided by (used in) financing activities	568	52	(2,526)
Net Increase (Decrease) in Cash and Cash Equivalents	194	(1,149)	(2,153)
Cash and Cash Equivalents at Beginning of Year	1,545	2,694	4,847
Cash and Cash Equivalents at End of Year	\$ 1,739	\$ 1,545	\$ 2,694

See accompanying Notes to Consolidated Financial Statements.

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HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED EQUITY

	Mandatory Convertible Preferred Stock	Common Stock	Capital in Excess of Par	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Hess Stockholders' Equity	Noncontrolling Interests	Total Equity
	(In millions)							
Balance at December 31, 2017	\$ 1	\$ 315	\$ 5,824	\$ 5,597	\$ (686)	\$ 11,051	\$ 1,303	\$ 12,354
Cumulative effect of adoption of new accounting standards	—	—	—	101	(101)	—	—	—
Net income (loss)	—	—	—	(282)	—	(282)	167	(115)
Other comprehensive income (loss)	—	—	—	—	481	481	—	481
Share-based compensation	—	1	103	—	—	104	—	104
Dividends on preferred stock	—	—	—	(46)	—	(46)	—	(46)
Dividends on common stock	—	—	—	(299)	—	(299)	—	(299)
Common stock acquired and retired	—	(25)	(541)	(814)	—	(1,380)	—	(1,380)
Noncontrolling interests, net	—	—	—	—	—	—	(211)	(211)
Balance at December 31, 2018	\$ 1	\$ 291	\$ 5,386	\$ 4,257	\$ (306)	\$ 9,629	\$ 1,259	\$ 10,888
Net income (loss)	—	—	—	(408)	—	(408)	168	(240)
Other comprehensive income (loss)	—	—	—	—	(393)	(393)	—	(393)
Preferred stock conversion	(1)	12	(11)	—	—	—	—	—
Share-based compensation	—	2	123	—	—	125	—	125
Dividends on preferred stock	—	—	—	(4)	—	(4)	—	(4)
Dividends on common stock	—	—	—	(310)	—	(310)	—	(310)
Conversion of Midstream structure	—	—	15	—	—	15	(22)	(7)
Sale of water business to Hess Infrastructure Partners	—	—	78	—	—	78	(78)	—
Noncontrolling interests, net	—	—	—	—	—	—	(353)	(353)
Balance at December 31, 2019	\$ —	\$ 305	\$ 5,591	\$ 3,535	\$ (699)	\$ 8,732	\$ 974	\$ 9,706
Net income (loss)	—	—	—	(3,093)	—	(3,093)	254	(2,839)
Other comprehensive income (loss)	—	—	—	—	(56)	(56)	—	(56)
Share-based compensation	—	2	93	(5)	—	90	—	90
Dividends on common stock	—	—	—	(307)	—	(307)	—	(307)
Noncontrolling interests, net	—	—	—	—	—	—	(259)	(259)
Balance at December 31, 2020	\$ —	\$ 307	\$ 5,684	\$ 130	\$ (755)	\$ 5,366	\$ 969	\$ 6,335

See accompanying Notes to Consolidated Financial Statements.

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1. Nature of Operations, Basis of Presentation and Summary of Accounting Policies

Unless the context indicates otherwise, references to “Hess”, “the Corporation”, “Registrant”, “we”, “us” and “our” refer to the consolidated business operations of Hess Corporation and its affiliates.

Nature of Business: Hess Corporation, incorporated in the State of Delaware in 1920, is a global E&P company engaged in exploration, development, production, transportation, purchase and sale of crude oil, natural gas liquids, and natural gas with production operations located primarily in the United States (U.S.), Guyana, the Malaysia/Thailand Joint Development Area (JDA), Malaysia, and Denmark. We conduct exploration activities primarily offshore Guyana, the U.S. Gulf of Mexico, and offshore Suriname and Canada.

Our Midstream operating segment, which is comprised of Hess Corporation’s 47% consolidated ownership interest in Hess Midstream LP at December 31, 2020 (see *Note 4, Hess Midstream LP*) provides fee-based services, including gathering, compressing and processing natural gas and fractionating NGL; gathering, termining, loading and transporting crude oil and NGL; storing and termining propane, and water handling services primarily in the Bakken shale play in the Williston Basin area of North Dakota.

Basis of Presentation and Principles of Consolidation: The consolidated financial statements include the accounts of Hess Corporation and entities in which we own more than a 50% voting interest. Commencing December 16, 2019, we consolidate Hess Midstream LP, a variable interest entity that acquired Hess Infrastructure Partners LP (HIP), based on our conclusion that we have the power through Hess Corporation’s 47% consolidated ownership interest in Hess Midstream LP to direct those activities that most significantly impact the economic performance of Hess Midstream LP, and are obligated to absorb losses or have the right to receive benefits that could potentially be significant to Hess Midstream LP. Prior to December 16, 2019, we consolidated HIP, also a variable interest entity based on the conclusion that we had the power to direct the activities that most significantly impacted the economic performance of HIP, and were obligated to absorb losses or had the right to receive benefits that could potentially be significant to HIP. Our undivided interests in unincorporated oil and gas E&P ventures are proportionately consolidated. Investments in affiliated companies, 20% to 50% owned and where we have the ability to influence the operating or financial decisions of the affiliate, are accounted for using the equity method.

Estimates and Assumptions: In preparing financial statements in conformity with GAAP, management makes estimates and assumptions that affect the reported amounts of assets and liabilities in the *Consolidated Balance Sheet* and revenues and expenses in the *Statement of Consolidated Income*. Actual results could differ from those estimates. Estimates made by management include oil and gas reserves, asset and other valuations, depreciable lives, pension liabilities, legal and environmental obligations, asset retirement obligations and income taxes.

Revenue Recognition:

Exploration and Production

The E&P segment recognizes revenue from the sale of crude oil, NGL, and natural gas as performance obligations under contracts with customers are satisfied. Our responsibilities to deliver each unit of quantity of crude oil, NGL, and natural gas under these contracts represent separate, distinct performance obligations. These performance obligations are satisfied at the point in time control of each unit of quantity transfers to the customer. Generally, the control of each unit of quantity transfers to the customer upon the transfer of legal title at the point of physical delivery. Pricing is variable and is determined with reference to a particular market or pricing index, plus or minus adjustments reflecting quality or location differentials.

For long-term international natural gas contracts with ship-or-pay provisions, our obligation to stand-ready to provide a minimum volume over each commitment period represents separate, distinct performance obligations. Penalties owed against future deliveries of natural gas due to delivery of volumes below minimum delivery commitments are recognized as reductions to revenue in the commitment period when the shortfall occurs. Long-term international natural gas contracts may also contain take-or-pay provisions whereby the customer is required to pay for volumes not taken that are below minimum volume commitments but the customer has certain make-up rights to receive shortfall volumes in subsequent periods. Shortfall payments received from customers when volumes purchased are below the minimum volume commitment are deferred upon receipt as a contract liability. Revenue is recognized at the earlier of when we deliver the make-up volumes in subsequent periods or when it becomes remote that the customer will exercise their make-up rights.

Certain crude oil, NGL, and natural gas volumes are purchased by Hess from third parties, including working interest partners and royalty owners in certain Hess-operated properties, before they are sold to customers. Where control over the crude oil, NGL, or natural gas transfers to Hess before the volumes are transferred to the customer, revenue and the associated cost of purchased volumes are presented on a gross basis in the *Statement of Consolidated Income* within Sales and other operating revenues and Marketing, including purchased oil and gas, respectively. Where control of crude oil, NGL, or natural gas is not transferred to Hess, revenue is

presented net of the associated cost of purchased volumes within Sales and other operating revenues in the *Statement of Consolidated Income*.

Contract Duration and Pricing:

Contracts with customers for the sale of U.S. crude oil, NGL, and natural gas primarily include those contracts that involve the short-term sale of volumes during a specified period, and those contracts that automatically renew on a periodic basis until either party cancels. We have certain long-term contracts with customers for the sale of U.S. natural gas and NGL that have remaining durations ranging from one to twelve years.

Contracts with customers for the sale of international crude oil involve the short-term sale of volumes during a specified period. Pricing is determined with reference to a particular market or pricing index, plus or minus adjustments reflecting quality or location differentials, shortly after control of the volumes transfers to the customer. International contracts with customers for the sale of natural gas are in the form of natural gas sales agreements with government entities that have durations that are aligned with the durations of production sharing contracts or other contractual arrangements with host governments. Pricing is determined using contractual formulas that are based on the price of alternative fuels as obtained from price indices and other factors.

Contract Balances:

Our right to receive or collect payment from the customer is aligned with the timing of revenue recognition except in situations when we receive shortfall payments under contracts with take-or-pay provisions with customer make-up rights. At December 31, 2020 and 2019, there were no contract assets or contract liabilities.

Generally, we receive payments from customers on a monthly basis, shortly after the physical delivery of the crude oil, NGL, or natural gas.

Transaction Price Allocated to Remaining Performance Obligations:

The transaction price allocated to our wholly unsatisfied performance obligations on uncompleted contracts is variable. Further, many of our contracts with customers have durations of less than twelve months. Accordingly, we have elected under the provisions of Accounting Standards Codification (ASC) 606 the exemption from disclosure of revenue recognizable in future periods as these performance obligations are satisfied.

Sales-based Taxes:

We exclude sales-based taxes that are collected from customers from the transaction price in our contracts with customers. Accordingly, revenue from contracts with customers is net of sales-based taxes that are collected from customers and remitted to taxing authorities.

Midstream

Our Midstream segment provides gathering, compression, processing, fractionation, storage, terminaling, loading and transportation, and water handling services.

The Midstream segment has multiple long-term, fee-based commercial agreements with certain subsidiaries of Hess, each generally with an initial ten-year term that can be extended for an additional ten-year term at the unilateral right of Hess Midstream. These contracts have minimum volumes the customer is obligated to provide each calendar quarter. The minimum volume commitments are subject to fluctuation based on nominations covering substantially all of our E&P segment's production and projected third-party volumes that will be purchased in the Bakken. As the minimum volume commitments are subject to fluctuation, and as these contracts contain fee inflation escalators and fee recalculation mechanisms, substantially all of the transaction price at contract inception is variable. The midstream segment also has long-term, fee based commercial agreements for water handling services with a subsidiary of Hess with an initial 14 year term that can be extended for an additional ten-year term at the unilateral right of Hess Midstream. Water handling services are provided for an agreed-upon fee per barrel or the reimbursement of third-party fees.

The Midstream segment's responsibilities to provide each of the above services for each year under each of the commercial agreements are considered separate, distinct performance obligations. Revenue is recognized for each performance obligation under these commercial agreements over-time as services are rendered using the output method, measured using the amount of volumes serviced during the period. The Midstream segment has elected the practical expedient under the provisions of ASC 606, *Revenue from Contracts with Customers* to recognize revenue in the amount it is entitled to invoice. If the commercial agreements have ship-or-pay provisions, the Midstream segment's responsibility to stand-ready to service a minimum volume over each quarterly commitment period represent separate, distinct performance obligations. Shortfall payments received under ship-or-pay provisions are recognized as revenue in the calendar quarter the shortfall occurs as the customer does not have make-up rights beyond the calendar

quarter end of the quarterly commitment period. All revenues, receivables, and contract balances arising from the commercial agreements between the Midstream segment and the Hess subsidiaries that are the counterparty to the commercial agreements are eliminated upon consolidation.

On December 30, 2020, Hess Midstream exercised its renewal options to extend the terms of certain gas gathering, crude oil gathering, gas processing and fractionation, storage, and terminal and export commercial agreements for the secondary term through December 31, 2033. There were no changes to any provisions of the existing commercial agreements as a result of the exercise of the renewal options.

Exploration and Development Costs: E&P activities are accounted for using the successful efforts method. Costs of acquiring unproved and proved oil and gas leasehold acreage, including lease bonuses, brokers' fees and other related costs are capitalized. Annual lease rentals, exploration expenses and exploratory dry hole costs are expensed as incurred. Costs of drilling and equipping productive wells, including development dry holes, and related production facilities are capitalized.

The costs of exploratory wells that find oil and gas reserves are capitalized pending determination of whether proved reserves have been found. Exploratory drilling costs remain capitalized after drilling is completed if (1) the well has found a sufficient quantity of reserves to justify completion as a producing well and (2) sufficient progress is being made in assessing the reserves and the economic and operational viability of the project. If either of those criteria is not met, or if there is substantial doubt about the economic or operational viability of a project, the capitalized well costs are charged to expense. Indicators of sufficient progress in assessing reserves and the economic and operating viability of a project include commitment of project personnel, active negotiations for sales contracts with customers, negotiations with governments, operators and contractors, firm plans for additional drilling and other factors.

Depreciation, Depletion and Amortization: We record depletion expense for acquisition costs of proved properties using the units of production method over proved oil and gas reserves. Depreciation and depletion expense for oil and gas production facilities and wells is calculated using the units of production method over proved developed oil and gas reserves. Provisions for impairment of undeveloped oil and gas leases are based on periodic evaluations and other factors. Depreciation of all other plant and equipment is determined on the straight-line method based on estimated useful lives.

Capitalized Interest: Interest from external borrowings is capitalized on material projects using the weighted average cost of outstanding borrowings until the project is substantially complete and ready for its intended use, which for oil and gas assets is at first production from the field. Capitalized interest is depreciated in the same manner as the depreciation of the underlying assets.

Impairment of Long-lived Assets: We review long-lived assets, including oil and gas fields, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts of the long-lived assets are not expected to be recovered by estimated undiscounted future net cash flows, the assets are impaired and an impairment loss is recorded. The amount of impairment is measured based on the estimated fair value of the assets generally determined by discounting anticipated future net cash flows, an income valuation approach, or by a market-based valuation approach, which are Level 3 fair value measurements.

In the case of oil and gas fields, the present value of future net cash flows is based on management's best estimate of future prices, which is determined with reference to recent historical prices and published forward prices, applied to projected production volumes and discounted at a risk-adjusted rate. The projected production volumes represent reserves, including probable reserves, expected to be produced based on a projected amount of capital expenditures. The production volumes, prices and timing of production are consistent with internal projections and other externally reported information. Oil and gas prices used for determining asset impairment will generally differ from those used in the standardized measure of discounted future net cash flows reported in *Supplementary Oil and Gas Data*, since the standardized measure requires the use of historical twelve-month average prices. As a result of the significant decline in crude oil prices in the first quarter of 2020, we tested our oil and gas properties for impairment at March 31, 2020. See *Note 12, Impairment*.

Impairment of Goodwill: Goodwill is tested for impairment annually on October 1st or when events or circumstances indicate that the carrying amount of the goodwill may not be recoverable. To determine whether goodwill is impaired, the fair value of a reporting unit is compared with its carrying amount, including goodwill. If the fair value of the reporting unit exceeds its carrying value, goodwill is not impaired. If the carrying value of the reporting unit exceeds its fair value, an impairment charge would be recorded for the excess of the carrying value over fair value, limited by the amount of goodwill allocated to the reporting unit. At December 31, 2020, goodwill of \$360 million relates to the Midstream operating segment.

Cash and Cash Equivalents: Cash and cash equivalents primarily comprises cash on hand and on deposit, as well as highly liquid investments that are readily convertible into cash and have maturities of three months or less when acquired.

Inventories: Produced and unsold crude oil and NGL are valued at the lower of cost or net realizable value. Cost is determined using the average cost of production plus any transport cost incurred in bringing the volumes to their present location. Materials and

supplies are valued at cost. Obsolete or surplus materials identified during periodic reviews are valued at the lower of cost or estimated net realizable value.

Leases: We determine if an arrangement is a lease at inception by evaluating whether the contract conveys the right to control an identified asset during the period of use. Right-of-use (ROU) assets represent our right to use an identified asset for the lease term and lease obligations represent our obligation to make payments as set forth in the lease arrangement. ROU assets and lease liabilities are recognized in the *Consolidated Balance Sheet* as operating leases or finance leases at the commencement date based on the present value of the minimum lease

payments over the lease term. Where the implicit discount rate in a lease is not readily determinable, we use our incremental borrowing rate based on information available at the commencement date for determining the present value of the minimum lease payments. The lease term used in measurement of our lease obligations includes options to extend or terminate the lease when, in our judgment, it is reasonably certain that we will exercise that option. Variable lease payments that depend on an index or a rate are included in the measurement of lease obligations using the index or rate at the commencement date. Variable lease payments that vary because of changes in facts or circumstances after the commencement date of the lease are not included in the minimum lease payments used to measure lease obligations. We have agreements that include financial obligations for lease and nonlease components. For purposes of measuring lease obligations, we have elected not to separate nonlease components from lease components for the following classes of assets: drilling rigs, office space, offshore vessels, and aircraft. We apply a portfolio approach to account for operating lease ROU assets and liabilities for certain vehicles, railcars, field equipment and office equipment leases.

Finance lease cost is recognized as amortization of the ROU asset and interest expense on the lease liability. Operating lease cost is generally recognized on a straight-line basis. Operating lease costs for drilling rigs used to drill development wells and successful exploration wells are capitalized. Operating lease cost for other ROU assets used in oil and gas producing activities are either capitalized or expensed on a straight-line basis based on the nature of operation for which the ROU asset is utilized.

Leases with an initial term of 12 months or less are not recorded on the balance sheet as permitted under ASC 842. We recognize lease cost for short-term leases on a straight-line basis over the term of the lease. Some of our leases include one or more options to renew. The renewal option is at our sole discretion and is not included in the lease term for measurement of the lease obligation unless we are reasonably certain at the commencement date of the lease, to renew the lease.

Income Taxes: Deferred income taxes are determined using the liability method. We have net operating loss carryforwards or credit carryforwards in multiple jurisdictions and have recorded deferred tax assets for those losses and credits. Additionally, we have deferred tax assets due to temporary differences between the book basis and tax basis of certain assets and liabilities. Regular assessments are made as to the likelihood of those deferred tax assets being realized. If, when tested under the relevant accounting standards, it is more likely than not that some or all of the deferred tax assets will not be realized, a valuation allowance is recorded to reduce the deferred tax assets to the amount that is expected to be realized. The accounting standards require the evaluation of all available positive and negative evidence giving weight based on the evidence's relative objectivity. In evaluating potential sources of positive evidence, we consider the reversal of taxable temporary differences, taxable income in carryback and carryforward periods, the availability of tax planning strategies, the existence of appreciated assets, estimates of future taxable income, and other factors. In evaluating potential sources of negative evidence, we consider a cumulative loss in recent years, any history of operating losses or tax credit carryforwards expiring unused, losses expected in early future years, unsettled circumstances that, if unfavorably resolved, would adversely affect future operations and profit levels on a continuing basis in future years, and any carryback or carryforward period so brief that a significant deductible temporary difference expected to reverse in a single year would limit realization of tax benefits. We assign cumulative historical losses significant weight in the evaluation of realizability relative to more subjective evidence such as forecasts of future income. In addition, we recognize the financial statement effect of a tax position only when management believes that it is more likely than not, that based on the technical merits, the position will be sustained upon examination. We are no longer indefinitely reinvested with respect to the book in excess of tax basis in the investment in our foreign subsidiaries. Because of U.S. tax reform we expect that the future reversal of such temporary differences will occur free of material taxation. We classify interest and penalties associated with uncertain tax positions as income tax expense. We account for the U.S. tax effect of global intangible low-taxed income earned by foreign subsidiaries in the period that such income is earned. We utilize the aggregate approach for releasing disproportionate income tax effects from *Accumulated other comprehensive income (loss)*.

Asset Retirement Obligations: We have material legal obligations to remove and dismantle long-lived assets and to restore land or the seabed at certain E&P locations. We initially recognize a liability for the fair value of legally required asset retirement obligations in the period in which the retirement obligations are incurred and capitalize the associated asset retirement costs as part of the carrying amount of the long-lived assets. In subsequent periods, the liability is accreted, and the asset is depreciated over the useful life of the related asset. Fair value is determined by applying a credit adjusted risk-free rate to the undiscounted expected future abandonment expenditures. Changes in estimates prior to settlement result in adjustments to both the liability and related asset values, unless the field has ceased production, in which case changes are recognized in the *Statement of Consolidated Income*.

Retirement Plans: We recognize the funded status of defined benefit postretirement plans in the *Consolidated Balance Sheet*. The funded status is measured as the difference between the fair value of plan assets and the projected benefit obligation. We recognize the net changes in the funded status of these plans in the year in which such changes occur. Actuarial gains and losses in

excess of 10% of the greater of the benefit obligation or the market value of assets are amortized over the average remaining service period of active employees or the remaining average expected life if a plan's participants are predominantly inactive.

Derivatives: We utilize derivative instruments for financial risk management activities. In these activities, we may use futures, forwards, options and swaps, individually or in combination, to mitigate our exposure to fluctuations in prices of crude oil and natural gas, as well as changes in interest and foreign currency exchange rates.

All derivative instruments are recorded at fair value in the *Consolidated Balance Sheet*. Our policy for recognizing the changes in fair value of derivatives varies based on the designation of the derivative. The changes in fair value of derivatives that are not designated as hedges are recognized currently in earnings. Derivatives may be designated as hedges of expected future cash flows or forecasted transactions (cash flow hedges), or hedges of changes in fair value of recognized assets and liabilities or of unrecognized firm commitments (fair value hedges). Changes in fair value of derivatives that are designated as cash flow hedges are recorded as a component of other comprehensive income (loss). Amounts included in Accumulated other comprehensive income (loss) for cash flow hedges are reclassified into earnings in the same period that the hedged item is recognized in earnings. Changes in fair value of derivatives designated as fair value hedges are recognized currently in earnings. The change in fair value of the related hedged item is recorded as an adjustment to its carrying amount and recognized currently in earnings.

Fair Value Measurements: We use various valuation approaches in determining fair value for financial instruments, including the market and income approaches. Our fair value measurements also include non-performance risk and time value of money considerations. Counterparty credit is considered for receivable balances, and our credit is considered for accrued liabilities. We also record certain nonfinancial assets and liabilities at fair value when required by GAAP. These fair value measurements are recorded in connection with business combinations, qualifying nonmonetary exchanges, the initial recognition of asset retirement obligations and any impairment of long-lived assets, equity method investments or goodwill. We determine fair value in accordance with the fair value measurements accounting standard which established a hierarchy for the inputs used to measure fair value based on the source of the inputs, which generally range from quoted prices for identical instruments in a principal trading market (Level 1) to estimates determined using related market data (Level 3), including discounted cash flows and other unobservable data. Measurements derived indirectly from observable inputs or from quoted prices from markets that are less liquid are considered Level 2. When Level 1 inputs are available within a particular market, those inputs are selected for determination of fair value over Level 2 or 3 inputs in the same market. Multiple inputs may be used to measure fair value; however, the level assigned to a fair value measurement is based on the lowest significant input level within this fair value hierarchy.

Details on the methods and assumptions used to determine the fair values are as follows:

Fair value measurements based on Level 1 inputs: Measurements that are most observable are based on quoted prices of identical instruments obtained from the principal markets in which they are traded. Closing prices are both readily available and representative of fair value. Market transactions occur with sufficient frequency and volume to assure liquidity.

Fair value measurements based on Level 2 inputs: Measurements derived indirectly from observable inputs or from quoted prices from markets that are less liquid are considered Level 2. Measurements based on Level 2 inputs include over-the-counter derivative instruments that are priced on an exchange-traded curve but have contractual terms that are not identical to exchange-traded contracts.

Fair value measurements based on Level 3 inputs: Measurements that are least observable are estimated from related market data, determined from sources with little or no market activity for comparable contracts or are positions with longer durations. Fair values determined using discounted cash flows and other unobservable data are also classified as Level 3.

Netting of Financial Instruments: We generally enter into master netting arrangements to mitigate legal and counterparty credit risk. Master netting arrangements are generally accepted overarching master contracts that govern all individual transactions with the same counterparty entity as a single legally enforceable agreement. The U.S. Bankruptcy Code provides for the enforcement of certain termination and netting rights under certain types of contracts upon the bankruptcy filing of a counterparty, commonly known as the “safe harbor” provisions. If a master netting arrangement provides for termination and netting upon the counterparty’s bankruptcy, these rights are generally enforceable with respect to “safe harbor” transactions. If these arrangements provide the right of offset and our intent and practice is to offset amounts in the case of such a termination, our policy is to record the fair value of derivative assets and liabilities on a net basis. In the normal course of business, we rely on legal and credit risk mitigation clauses providing for adequate credit assurance as well as close-out netting, including two-party netting and single counterparty multilateral netting. As applied to us, “two-party netting” is the right to net amounts owing under safe harbor transactions between a single defaulting counterparty entity and a single Hess entity, and “single counterparty multilateral netting” is the right to net amounts owing under safe harbor transactions among a single defaulting counterparty entity and multiple Hess entities. We are reasonably assured that these netting rights would be upheld in a bankruptcy proceeding in the U.S. in which the defaulting counterparty is a debtor under the U.S. Bankruptcy Code.

Share-based Compensation: We account for share-based compensation based on the fair value of the award on the date of grant. The fair value of all share-based compensation is recognized over the requisite service period for the entire award, whether the award was granted with ratable or cliff vesting terms, net of actual forfeitures. We estimate fair value at the date of grant using a

Black-Scholes valuation model for employee stock options and a Monte Carlo simulation model for performance share units (PSUs). Fair value of restricted stock is based on the market value of the underlying shares at the date of grant.

Foreign Currency Translation: The U.S. Dollar is the functional currency (primary currency in which business is conducted) for our foreign operations. Adjustments resulting from remeasuring monetary assets and liabilities that are denominated in a currency other than the functional currency are recorded in *Other, net* in the *Statement of Consolidated Income*.

Maintenance and Repairs: Maintenance and repairs are expensed as incurred. Capital improvements are recorded as additions in Property,

plant and equipment.

Environmental Expenditures: We accrue and expense the undiscounted environmental costs necessary to remediate existing conditions related to past operations when the future costs are probable and reasonably estimable. At year-end 2020, our reserve for estimated remediation liabilities was approximately \$65 million. Environmental expenditures that increase the life or efficiency of property or reduce or prevent future adverse impacts to the environment are capitalized.

New Accounting Pronouncements: In the first quarter of 2020, we adopted Accounting Standards Update (ASU) 2016-13, *Financial Instruments – Credit Losses*. This ASU makes changes to the impairment model for trade receivables, net investments in leases, debt securities, loans and certain other instruments. The standard requires the use of a forward-looking "expected loss" model compared with the prior "incurred loss" model. We calculate expected credit losses for our receivables using the probability of default and the expected loss given default. Historical data, current market conditions, and forecasts of future economic conditions are used to determine the probability of default and the expected loss given default. The adoption of this ASU did not have a material impact to our financial statements.

2. Inventories

Inventories at December 31 were as follows:

	2020	2019
	(In millions)	
Crude oil and natural gas liquids	\$ 226	\$ 92
Materials and supplies	152	169
Total Inventories	\$ 378	\$ 261

In the first quarter of 2020, we recognized charges of \$53 million (\$52 million after income taxes) recorded in *Marketing, including purchased oil and gas* to reflect crude oil inventories at net realizable value at March 31, 2020.

In 2020, we chartered three VLCCs to load and transport a total of 6.3 million barrels of Bakken crude oil for sale in Asian markets. The first VLCC cargo of 2.1 million barrels was sold in September 2020. We have entered into agreements for the sale of the remaining 4.2 million barrels of crude oil loaded on the second and third VLCCs in the first quarter of 2021. At December 31, 2020, crude oil inventories included \$164 million associated with the cost of these volumes.

3. Property, Plant and Equipment

Property, plant and equipment at December 31 were as follows:

	2020	2019
	(In millions)	
Exploration and Production		
Unproved properties	\$ 164	\$ 168
Proved properties	2,930	3,304
Wells, equipment and related facilities	23,224	28,404
	26,318	31,876
Midstream	4,163	3,904
Corporate and Other	38	40
Total — at cost	30,519	35,820
Less: Reserves for depreciation, depletion, amortization and lease impairment	16,404	19,006
Property, Plant and Equipment — Net	\$ 14,115	\$ 16,814

Capitalized Exploratory Well Costs: The following table discloses the amount of capitalized exploratory well costs pending determination of proved reserves at December 31 and the changes therein during the respective years:

	2020	2019	2018
	(In millions)		
Balance at January 1	\$ 584	\$ 418	\$ 304
Additions to capitalized exploratory well costs pending the determination of proved reserves	111	224	128
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(111)	(58)	—
Capitalized exploratory well costs charged to expense	(125)	—	(14)
Balance at December 31	\$ 459	\$ 584	\$ 418

Number of Wells at December 31

223124

During the three years ended December 31, 2020, additions to capitalized exploratory well costs primarily related to drilling at the Stabroek Block, offshore Guyana. Other drilling activity included the Esso prospect in the Gulf of Mexico during 2019 and the Bunga prospect in the North Malay Basin, offshore Peninsular Malaysia during 2018.

Reclassifications to wells, facilities and equipment based on the determination of proved reserves in 2020 resulted from sanctions of the Payara Field development on the Stabroek Block, offshore Guyana, and an additional phase of development at the North Malay Basin, offshore Peninsular Malaysia. In 2019, reclassifications to wells, facilities and equipment resulted from sanction of the Liza Phase 2 development on the Stabroek Block and the Esso tieback well to the Tubular Bells Field in the Gulf of Mexico.

Capitalized exploratory well costs charged to expense in 2020 included \$125 million, primarily related to the northern portion of the Shenzi Field (Hess 28%) in the Gulf of Mexico due to reprioritization of our forward capital program in response to the significant decline in crude oil prices. In 2018, in Canada, offshore Nova Scotia (Hess 50% participating interest), the operator, BP Canada, completed drilling of the Aspy exploration well, which did not encounter commercial quantities of hydrocarbons. As a result, we expensed well costs totaling \$120 million in 2018, of which \$14 million was incurred in 2017. The preceding table excludes well costs incurred and expensed during 2020 of \$67 million (2019: \$49 million; 2018: \$151 million).

Exploratory well costs capitalized for greater than one year following completion of drilling were \$342 million at December 31, 2020, separated by year of completion as follows (in millions):

2019	\$	173
2018		105
2017		27
2016		—
2015		37
	\$	<u>342</u>

Guyana: Approximately 85% of the capitalized well costs in excess of one year relate to successful exploration wells where hydrocarbons were encountered on the Stabroek Block (Hess 30%), offshore Guyana. The operator plans further appraisal drilling and is conducting pre-development planning for additional phases of development beyond the three previously sanctioned development projects on the Block.

JDA: Approximately 10% of the capitalized well costs in excess of one year relates to the JDA (Hess 50%) in the Gulf of Thailand, where hydrocarbons were encountered in three successful exploration wells drilled in the western part of Block A-18. The operator has submitted a development plan concept to the regulator to facilitate ongoing commercial negotiations for an extension of the existing gas sales contract to include development of the western part of the Block.

Malaysia: Approximately 5% of the capitalized well costs in excess of one year relates to North Malay Basin (Hess 50%), offshore Peninsular Malaysia, where hydrocarbons were encountered in one successful exploration well. Subsurface evaluation and pre-development studies for future phases of development are ongoing.

4. Hess Midstream LP

Prior to December 16, 2019, the Midstream segment was primarily comprised of HIP, a 50/50 joint venture between Hess Corporation and Global Infrastructure Partners (GIP), formed to own, operate, develop and acquire a diverse set of midstream assets to provide fee-based services to Hess and third-party customers. HIP was initially formed on May 21, 2015, with Hess selling 50% of HIP to GIP for approximately \$2.6 billion on July 1, 2015.

On April 10, 2017, HIP completed an initial public offering (IPO) of 16,997,000 common units, representing 30.5% limited partnership interests in its subsidiary Hess Midstream Partners LP (Hess Midstream Partners), for net proceeds of approximately

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\$365.5 million. In connection with the IPO, HIP contributed a 20% controlling economic interest in each of Hess North Dakota Pipeline Operations LP, Hess TGP Operations LP, and Hess North Dakota Export Logistics Operations LP, and a 100% economic interest in Hess Mentor Storage Holdings LLC (collectively the “Contributed Businesses”). In exchange for the contributed businesses, Hess and GIP each received common and subordinated units representing a direct 33.75% limited partner interest in Hess Midstream Partners and a 50% indirect ownership interest through HIP in Hess Midstream Partners’ general partner, which had a 2% economic interest in Hess Midstream Partners plus incentive distribution rights.

On March 1, 2019, HIP acquired Hess’s existing Bakken water services business for \$225 million in cash. As a result of this transaction, we recorded an after-tax gain of \$78 million in additional paid-in capital with an offsetting reduction to noncontrolling interest to reflect the adjustment to GIP’s noncontrolling interest in HIP. On March 22, 2019, HIP and Hess Midstream Partners acquired crude oil and gas gathering assets, and HIP acquired water gathering assets of Summit Midstream Partners LP’s Tioga Gathering System for aggregate cash consideration of approximately \$90

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million, with the potential for an additional \$10 million of contingent payments in future periods subject to certain future performance metrics. On January 25, 2018, Hess Midstream Partners entered into a 50/50 joint venture with Targa Resources Corp. to construct a new 200 million standard cubic feet per day gas processing plant called Little Missouri 4 (LM4). The plant, which is operated by Targa, was placed into service in the third quarter of 2019.

On December 16, 2019, Hess Midstream Partners acquired HIP, including HIP's 80% interest in Hess Midstream Partners' oil and gas midstream assets, HIP's water services business and the outstanding economic general partner interest and incentive distribution rights in Hess Midstream Partners LP. In addition, Hess Midstream Partners' organizational structure converted from a master limited partnership into an "Up-C" structure in which Hess Midstream Partners' public unitholders received newly issued Class A shares in a new public entity named Hess Midstream LP (Hess Midstream), which is taxed as a corporation for U.S. federal and state income tax purposes. Hess Midstream Partners changed its name to "Hess Midstream Operations LP" (HESM Opco) and became a consolidated subsidiary of Hess Midstream, the new publicly listed entity. As consideration for the acquisition, Hess received a cash payment of \$301 million and approximately 115 million newly issued HESM Opco Class B units. After giving effect to the acquisition and related transactions, public shareholders of Class A shares in Hess Midstream own 6% of the consolidated entity on an as-exchanged basis and Hess and GIP each own 47% of the consolidated entity on an as-exchanged basis, primarily through the sponsors' ownership of Class B units in HESM Opco that are exchangeable into Class A shares of Hess Midstream on a one-for-one basis, or referred to as "Hess Corporation's 47% consolidated ownership in Hess Midstream LP".

At December 31, 2020, Hess Midstream liabilities totaling \$2,026 million (2019: \$1,941 million) are on a nonrecourse basis to Hess Corporation, while Hess Midstream assets available to settle the obligations of Hess Midstream included Cash and cash equivalents totaling \$3 million (2019: \$3 million), Property, plant and equipment, net totaling \$3,111 million (2019: \$3,010 million) and an equity-method investment of \$108 million (2019: \$108 million) in LM4.

5. Accrued Liabilities

The following table provides detail of our accrued liabilities at December 31:

	2020	2019
	(In millions)	
Accrued capital expenditures	\$ 345	\$ 616
Accrued operating and marketing expenditures	325	479
Accrued payments to royalty and working interest owners	170	260
Accrued interest on debt	126	126
Accrued compensation and benefits	117	166
Current portion of asset retirement obligations	105	127
Other accruals	63	29
Total Accrued Liabilities	\$ 1,251	\$ 1,803

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6. Leases

Operating and finance lease obligations at December 31 included in the *Consolidated Balance Sheet* were as follows:

	Operating Leases		Finance Leases	
	2020	2019	2020	2019
	(In millions)			
Right-of-use assets — net (a)	\$ 426	\$ 447	\$ 168	\$ 299
Lease obligations:				
Current	\$ 63	\$ 182	\$ 18	\$ 17
Long-term	478	353	220	238
Total lease obligations	\$ 541	\$ 535	\$ 238	\$ 255

(a) At December 31, 2020, finance lease ROU assets had a cost of \$212 million (2019: \$381 million) and accumulated amortization of \$44 million (2019: \$82 million).

Lease obligations represent 100% of the present value of future minimum lease payments in the lease arrangement. Where we have contracted directly with a lessor in our role as operator of an unincorporated oil and gas venture, we bill our partners their proportionate share for reimbursements as payments under lease agreements become due pursuant to the terms of our joint operating and other agreements.

The nature of our leasing arrangements at December 31, 2020 was as follows:

Operating leases: In the normal course of business, we primarily lease drilling rigs, equipment, logistical assets (offshore vessels, aircraft, and shorebases), and office space.

Finance leases: In 2018, we entered into a sale and lease-back arrangement for a floating storage and offloading vessel (FSO) to handle produced condensate at North Malay Basin, offshore Peninsular Malaysia. At December 31, 2020, the remaining lease term for the FSO was 12.8 years.

Maturities of lease obligations at December 31, 2020 were as follows:

	Operating Leases	Finance Leases
	(In millions)	
2021	\$ 83	\$ 36
2022	83	36
2023	72	36
2024	71	36
2025	67	36
Remaining years	287	176
Total lease payments	663	356
Less: Imputed interest	(122)	(118)
Total lease obligations	\$ 541	\$ 238

The following information relates to the Operating and Finance leases at December 31:

	Operating Leases		Finance Leases	
	2020	2019	2020	2019
Weighted average remaining lease term	10.3 years	5.4 years	12.8 years	13.8 years
Range of remaining lease terms	0.1 - 15.5 years	0.1 - 16.1 years	12.8 years	13.8 years
Weighted average discount rate	4.0%	4.3%	7.9%	7.9%

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The components of lease costs for the years ended December 31, 2020 and 2019 were as follows:

	2020	2019
	(In millions)	
Operating lease cost	\$ 200	\$ 414
Finance lease cost:		
Amortization of leased assets	31	43
Interest on lease obligations	20	21
Short-term lease cost (a)	199	164
Variable lease cost (b)	38	89
Sublease income (c)	(15)	(12)
Total lease cost (d)	\$ 473	\$ 719

- (a) Short-term lease cost is primarily attributable to equipment used in global exploration, development, production, and crude oil marketing activities. Future short-term lease costs will vary based on activity levels of our operated assets.
- (b) Variable lease costs for drilling rigs result from differences in the minimum rate and the actual usage of the ROU asset during the lease period. Variable lease costs for logistical assets result from differences in stated monthly rates and total charges reflecting the actual usage of the ROU asset during the lease period. Variable lease costs for our office leases represent common area maintenance charges which have not been separated from lease components.
- (c) We sublease certain of our office space to third parties under our head lease.
- (d) Prior to the adoption of ASC 842, we incurred total rental expense of \$154 million and income from subleases of \$8 million in 2018.

The above lease costs represent 100% of the lease payments due for the period, including where we as operator have contracted directly with suppliers. As the payments under lease agreements where we are operator become due, we bill our partners their proportionate share for reimbursement pursuant to the terms of our joint operating agreements. Reimbursements are not reflected in the table above. Certain lease costs above associated with exploration and development activities are included in capital expenditures.

Supplemental cash flow information related to leases for the years ended December 31, 2020 and 2019 were as follows:

Operating Leases		Finance Leases	
2020	2019	2020	2019
(In millions)			

Cash paid for amounts included in the measurement of lease obligations:

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Operating cash flows (a)	\$	218	\$	419	\$	20	\$	21
Financing cash flows (a)		—		—		17		55
Noncash transactions:								
Leased assets recognized for new lease obligations incurred		51		14		—		—
Changes in leased assets and lease obligations due to lease modifications (b)		123		14		—		—

(a) Amounts represent gross lease payments before any recovery from partners.

(b) Primarily related to negotiated extensions of an office lease and offshore drilling rig leases.

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7. Debt

Total debt at December 31 consisted of the following:

	2020	2019
	(In millions)	
Debt - Hess Corporation:		
Fixed-rate public notes:		
3.5% due 2024	\$ 299	\$ 298
4.3% due 2027	994	992
7.9% due 2029	464	463
7.3% due 2031	628	628
7.1% due 2033	537	537
6.0% due 2040	741	741
5.6% due 2041	1,236	1,235
5.8% due 2047	494	494
Total fixed-rate public notes	5,393	5,388
Term loan due March 2023	988	—
Fair value adjustments - interest rate hedging	5	1
Total Debt - Hess Corporation	\$ 6,386	\$ 5,389
Debt - Midstream:		
Fixed-rate notes: 5.625% due 2026 - Hess Midstream Operations LP	\$ 789	\$ 787
Fixed-rate notes: 5.125% due 2028 - Hess Midstream Operations LP	542	540
Term loan A facility - Hess Midstream Operations LP	395	394
Revolving credit facility - Hess Midstream Operations LP	184	32
Total Debt - Midstream	\$ 1,910	\$ 1,753
Total Debt:		
Current maturities of long-term debt	\$ 10	\$ —
Long-term debt	8,286	7,142
Total Debt	\$ 8,296	\$ 7,142

At December 31, 2020, the maturity profile of total debt was as follows:

	Hess		
	Total	Corporation	Midstream
	(In millions)		
2021	\$ 10	\$ —	\$ 10
2022	20	—	20
2023	1,030	1,000	30
2024	824	300	524
2025	—	—	—
Thereafter	6,488	5,138	1,350
Total Borrowings	8,372	6,438	1,934
Less: Deferred financing costs and discounts	(76)	(52)	(24)
Total Debt (excluding interest)	\$ 8,296	\$ 6,386	\$ 1,910

No interest was capitalized in 2020 (2019: \$38 million; 2018: \$20 million).

Debt – Hess Corporation:*Senior unsecured fixed-rate public notes:*

At December 31, 2020, Hess Corporation's fixed-rate public notes had a gross principal amount of \$5,438 million (2019: \$5,438 million) and a weighted average interest rate of 5.9% (2019: 5.9%). The indentures for our fixed-rate public notes limit the ratio of secured debt to Consolidated Net Tangible Assets (as that term is defined in the indentures) to 15%. As of December 31, 2020, Hess Corporation was in compliance with this financial covenant.

Term loan and credit facility:

In 2020, we entered into a \$1 billion three year term loan agreement with a maturity date of March 16, 2023. Borrowings under the term loan generally bear interest at LIBOR plus an applicable margin of 2.25% until the term loan's first anniversary. The

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applicable margin varies based on the credit rating of the Corporation's senior unsecured long-term debt and will increase by 0.25% on each anniversary of the term loan.

In 2019, we entered into a new \$3.5 billion revolving credit facility with a maturity date of May 15, 2023, which replaced the Corporation's previous revolving credit facility. The new facility can be used for borrowings and letters of credit. Borrowings will generally bear interest at 1.30% above LIBOR, though the interest rate is subject to adjustment if the Corporation's credit rating changes. At December 31, 2020, Hess Corporation had no outstanding borrowings or letters of credit under this facility.

Both the term loan and revolving credit facility are subject to customary representations, warranties, customary events of default and covenants, including a financial covenant limiting the ratio of Total Consolidated Debt to Total Capitalization of the Corporation and its consolidated subsidiaries to 65%, and a financial covenant limiting the ratio of secured debt to Consolidated Net Tangible Assets of the Corporation and its consolidated subsidiaries to 15% (as these capitalized terms are defined in the credit agreement for the revolving credit facility and the term loan agreement). As of December 31, 2020, Hess Corporation was in compliance with these financial covenants.

The most restrictive of the financial covenants related to our fixed-rate public notes and our term loan and revolving credit facility would allow us to borrow up to an additional \$1,730 million of secured debt at December 31, 2020.

Other outstanding letters of credit at December 31 were as follows:

	2020	2019
	(In millions)	
Committed lines (a)	\$ 54	\$ 54
Uncommitted lines (a)	215	218
Total	\$ 269	\$ 272

(a) At December 31, 2020, committed and uncommitted lines have expiration dates through 2021.

Debt - Midstream:*Senior unsecured fixed-rate public notes:*

In November 2017, HIP issued \$800 million of 5.625% senior unsecured notes due in 2026. In December 2019, in connection with the acquisition of HIP and corporate restructuring described in *Note 4, Hess Midstream LP*, HESM Opco assumed \$800 million of outstanding HIP senior notes in a par-for-par exchange. The senior notes are guaranteed by certain subsidiaries of HESM Opco. In addition, in December 2019, HESM Opco issued \$550 million of 5.125% senior unsecured notes due in 2028. The notes are guaranteed by HESM Opco's direct and indirect wholly owned material domestic subsidiaries. Proceeds of the new notes were used to finance the acquisition of HIP and repay outstanding borrowings under HIP's credit facilities.

Credit facilities:

Prior to the closing of the December 2019 transaction, HIP had a \$600 million 5-year senior secured revolving credit facility and a \$200 million senior secured Term Loan A facility, while Hess Midstream Partners LP had a \$300 million 4-year senior secured syndicated revolving credit facility. In connection with the acquisition of HIP, both HIP and Hess Midstream Partners LP retired their existing senior secured revolving credit facilities and HESM Opco entered into a new 5-year senior secured syndicated revolving credit facility in the amount of \$1.0 billion. HIP also retired its senior secured Term Loan A facility, which had borrowings of \$190 million excluding deferred issuance costs, and HESM Opco entered into a fully drawn \$400 million 5-year Term Loan A facility, receiving cash of \$210 million at closing. The new revolving credit facility can be used for borrowings and letters of credit to fund HESM Opco's operating activities, capital expenditures, distributions and for other general corporate purposes. Borrowings under the 5-year Term Loan A facility will generally bear interest at LIBOR plus an applicable margin ranging from 1.55% to 2.50%, while the applicable margin for the 5-year syndicated revolving credit facility ranges from 1.275% to 2.000%. Pricing levels for the facility fee

and interest-rate margins are based on HESM Opco's ratio of total debt to EBITDA as defined in the credit facilities. If HESM Opco obtains an investment grade credit rating, the pricing levels will be based on HESM Opco's credit ratings in effect from time to time. The credit facilities contain covenants that require HESM Opco to maintain a ratio of total debt to EBITDA for the prior four fiscal quarters of not greater than 5.00 to 1.00 as of the last day of each fiscal quarter (5.50 to 1.00 during the specified period following certain acquisitions) and, prior to HESM Opco obtaining an investment grade credit rating, a ratio of secured debt to EBITDA for the prior four fiscal quarters of not greater than 4.00 to 1.00 as of the last day of each fiscal quarter. The credit facilities are secured by first-priority perfected liens on substantially all the presently owned and after-acquired assets of HESM Opco and its direct and indirect wholly owned material domestic subsidiaries, including equity interests directly owned by such entities, subject to certain customary exclusions. At December 31, 2020, borrowings of \$184 million were drawn under HESM Opco's revolving credit facility, and borrowings of \$400 million, excluding deferred issuance costs, were drawn under HESM Opco's Term Loan A facility. Borrowings under these credit facilities are non-recourse to Hess Corporation.

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8. Asset Retirement Obligations

The following table describes changes to our asset retirement obligations:

	2020	2019
	(In millions)	
Balance at January 1	\$ 1,024	\$ 857
Liabilities incurred	36	72
Liabilities settled or disposed of	(161)	(75)
Accretion expense	46	40
Revisions of estimated liabilities	52	129
Foreign currency remeasurement	2	1
Balance at December 31	\$ 999	\$ 1,024
Total Asset Retirement Obligations at December 31:		
Current portion of asset retirement obligations	\$ 105	\$ 127
Long-term asset retirement obligations	894	897
Total at December 31	\$ 999	\$ 1,024

The liabilities incurred in 2020 and 2019 primarily relate to operations in Guyana, the U.S. and Malaysia. The liabilities settled or disposed of in 2020 primarily reflect an asset sale in the Gulf of Mexico and abandonment activity completed in the Gulf of Mexico, the Bakken and the U.K. North Sea, while 2019 primarily relates to abandonment activity in the Gulf of Mexico and the Bakken. Revisions of estimated liabilities in 2020 and 2019 reflect an acceleration of planned abandonment activity in the Gulf of Mexico and changes in service and equipment rates.

Sinking fund deposits that are legally restricted for purposes of settling asset retirement obligations, which are reported in non-current Other assets in the *Consolidated Balance Sheet*, were \$207 million at December 31, 2020 (2019: \$178 million).

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9. Retirement Plans

We have funded noncontributory defined benefit pension plans for a significant portion of our employees. In addition, we have an unfunded supplemental pension plan covering certain employees, which provides incremental payments that would have been payable from our principal pension plans, were it not for limitations imposed by income tax regulations. The plans provide defined benefits based on years of service and final average salary to U.S. employees hired prior to January 1, 2017 and to U.K. employees. U.S. employees hired on or after January 1, 2017 participate under a cash accumulation formula and receive credits to a notional account based on a percentage of pensionable wages. Interest accrues on the balance in the notional account at a rate determined in accordance with plan provisions. Additionally, we maintain an unfunded postretirement medical plan that provides health benefits to certain U.S. qualified retirees from ages 55 through 65. The measurement date for all retirement plans is December 31.

The following table summarizes the benefit obligations, the fair value of plan assets, and the funded status of our pension and postretirement medical plans:

Funded	Unfunded	Postretirement
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Pension Plans		Pension Plan		Medical Plan	
2020	2019	2020	2019	2020	2019

(In millions)

Change in Benefit Obligation

Balance at January 1,	\$ 2,667	\$ 2,492	\$ 242	\$ 216	\$ 75	\$ 59
Service cost	37	33	13	11	3	2
Interest cost	68	82	5	7	1	2
Actuarial (gains) loss (a)	385	401	26	22	(8)	19
Single premium annuity contract payment	—	(249)	—	—	—	—
Benefit payments (b)	(93)	(113)	(17)	(14)	(6)	(7)
Foreign currency exchange rate changes	21	21	—	—	—	—
Balance at December 31, (c)	<u>3,085</u>	<u>2,667</u>	<u>269</u>	<u>242</u>	<u>65</u>	<u>75</u>

Change in Fair Value of Plan Assets

Balance at January 1,	\$ 2,732	\$ 2,568	\$ —	\$ —	\$ —	\$ —
Actual return on plan assets	378	462	—	—	—	—
Employer contributions	4	40	17	14	6	7
Single premium annuity contract payment	—	(249)	—	—	—	—
Benefit payments (b)	(93)	(113)	(17)	(14)	(6)	(7)
Foreign currency exchange rate changes	22	24	—	—	—	—
Balance at December 31,	<u>3,043</u>	<u>2,732</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>

Funded Status (Plan assets greater (less) than benefit obligations) at December 31, \$ (42) \$ 65 \$ (269) \$ (242) \$ (65) \$ (75)

Unrecognized Net Actuarial (Gains) Losses

\$ 900 \$ 756 \$ 86 \$ 65 \$ (19) \$ (12)

(a) Changes in discount rates resulted in actuarial losses of \$387 million in 2020 (2019: \$465 million). Changes in mortality assumptions resulted in actuarial gains of \$18 million in 2020 (2019: \$13 million).

(b) Benefit payments include lump-sum settlement payments of \$23 million in 2020 (2019: \$27 million).

(c) At December 31, 2020, the accumulated benefit obligation for the funded and unfunded defined benefit pension plans was \$2,993 million and \$228 million, respectively (2019: \$2,580 million and \$194 million, respectively).

Amounts recognized in the *Consolidated Balance Sheet* at December 31 consisted of the following:

Funded		Unfunded		Postretirement	
Pension Plans		Pension Plan		Medical Plan	
2020	2019	2020	2019	2020	2019

(In millions)

Noncurrent assets	\$ 45	\$ 71	\$ —	\$ —	\$ —	\$ —
Current liabilities	—	—	(49)	(32)	(7)	(8)
Noncurrent liabilities	(87)	(6)	(220)	(210)	(58)	(67)
Pension assets / (accrued benefit liability)	<u>\$ (42)</u>	<u>\$ 65</u>	<u>\$ (269)</u>	<u>\$ (242)</u>	<u>\$ (65)</u>	<u>\$ (75)</u>

Accumulated other comprehensive loss, pre-tax (a) \$ 900 \$ 756 \$ 86 \$ 65 \$ (19) \$ (12)

(a) The after-tax deficit reflected in Accumulated other comprehensive income (loss) was \$759 million at December 31, 2020 (2019: \$601 million deficit).

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The net periodic benefit cost for funded and unfunded pension plans, and the postretirement medical plan, is as follows:

Pension Plans			Postretirement Medical Plan		
2020	2019	2018	2020	2019	2018

(In millions)

Service cost	\$ 50	\$ 44	\$ 42	\$ 3	\$ 2	\$ 2
Interest cost	73	89	91	1	2	3
Expected return on plan assets	(180)	(180)	(194)	—	—	—
Amortization of unrecognized net actuarial losses (gains)	48	52	39	(1)	(1)	(2)
Settlement loss	—	93	4	—	—	—
Curtailment gain	—	—	—	—	—	(2)
Net Periodic Benefit Cost / (Income) (a)	<u>\$ (9)</u>	<u>\$ 98</u>	<u>\$ (18)</u>	<u>\$ 3</u>	<u>\$ 3</u>	<u>\$ 1</u>

(a) Net non-service cost, which are included in Other, net in the Statement of Consolidated Income, were income of \$59 million in 2020 (2019: \$55 million of expense);

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2018: \$61 million of income).

In 2019, the trust for the Hess Corporation Employees' Pension Plan (the "Plan") purchased a single premium annuity contract at a cost of \$249 million using assets of the Plan to settle and transfer certain of its obligations to a third party. The settlement transaction resulted in a noncash charge of \$88 million to recognize unamortized pension actuarial losses that is included in *Other, net* in the *Statement of Consolidated Income*.

In 2021, we forecast service cost for our pension and postretirement medical plans to be approximately \$55 million and net non-service cost of approximately \$85 million of income, which is comprised of interest cost of approximately \$55 million, amortization of unrecognized net actuarial losses of approximately \$55 million, and estimated expected return on plan assets of approximately \$195 million.

Assumptions: The weighted average actuarial assumptions used to determine benefit obligations at December 31 and net periodic benefit cost for the three years ended December 31 for our funded and unfunded pension plans were as follows:

	2020	2019	2018
<i>Benefit Obligations:</i>			
Discount rate	2.2%	2.9%	3.9%
Rate of compensation increase	3.8%	3.8%	3.8%
<i>Net Periodic Benefit Cost:</i>			
Discount rate			
Service cost	3.2%	3.9%	3.9%
Interest cost	2.6%	3.4%	3.3%
Expected return on plan assets	6.7%	7.1%	7.2%
Rate of compensation increase	3.8%	3.8%	4.5%

The actuarial assumptions used to determine benefit obligations at December 31 for the postretirement medical plan were as follows:

	2020	2019	2018
Discount rate	1.9%	2.8%	3.9%
Initial health care trend rate	6.0%	6.5%	6.9%
Ultimate trend rate	4.5%	4.5%	4.5%
Year in which ultimate trend rate is reached	2038	2038	2038

The assumptions used to determine net periodic benefit cost for each year were established at the end of each previous year while the assumptions used to determine benefit obligations were established at each year-end. The net periodic benefit cost and the actuarial present value of benefit obligations are based on actuarial assumptions that are reviewed on an annual basis. The discount rate is developed based on a portfolio of high-quality, fixed income debt instruments with maturities that approximate the expected payment of plan obligations.

The overall expected return on plan assets is developed from the expected future returns for each asset category, weighted by the target allocation of pension assets to that asset category. The future expected return assumptions for individual asset categories are largely based on inputs from various investment experts regarding their future return expectations for particular asset categories.

Our investment strategy is to maximize long-term returns at an acceptable level of risk through broad diversification of plan assets in a variety of asset classes. Asset classes and target allocations are determined by our investment committee and include domestic and foreign equities, fixed income, and other investments, including hedge funds, real estate and private equity. Investment managers are prohibited from investing in securities issued by us unless indirectly held as part of an index strategy. The majority of plan assets

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are highly liquid, providing ample liquidity for benefit payment requirements. The current target allocations for plan assets are 45% equity securities, 35% fixed income securities (including cash and short-term investment funds) and 20% to all other types of investments. Asset allocations are rebalanced on a periodic basis throughout the year to bring assets to within an acceptable range of target levels.

Fair value: The following tables provide the fair value of the financial assets of the funded pension plans at December 31, 2020 and 2019 in accordance with the fair value measurement hierarchy described in *Note 1, Nature of Operations, Basis of Presentation and Summary of Accounting Policies*.

	Net Asset				
	Level 1	Level 2	Level 3	Value (c)	Total
	(In millions)				
December 31, 2020					
Cash and Short-Term Investment Funds	\$ 44	\$ —	\$ —	\$ —	\$ 44

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Equities:					
U.S. equities (domestic)	585	—	—	164	749
International equities (non-U.S.)	94	43	—	352	489
Global equities (domestic and non-U.S.)	—	8	—	217	225
Fixed Income:					
Treasury and government related (a)	—	350	—	49	399
Mortgage-backed securities (b)	—	116	—	70	186
Corporate	—	381	—	62	443
Other:					
Hedge funds	—	—	—	73	73
Private equity funds	—	—	—	251	251
Real estate funds	23	—	—	161	184
Total investments	\$ 746	\$ 898	\$ —	\$ 1,399	\$ 3,043
December 31, 2019					
Cash and Short-Term Investment Funds	\$ 57	\$ —	\$ —	\$ —	\$ 57
Equities:					
U.S. equities (domestic)	638	—	—	—	638
International equities (non-U.S.)	80	37	—	302	419
Global equities (domestic and non-U.S.)	—	8	—	196	204
Fixed Income:					
Treasury and government related (a)	—	372	—	56	428
Mortgage-backed securities (b)	—	141	—	30	171
Corporate	—	293	—	82	375
Other:					
Hedge funds	—	—	—	65	65
Private equity funds	—	—	—	191	191
Real estate funds	27	—	—	157	184
Total investments	\$ 802	\$ 851	\$ —	\$ 1,079	\$ 2,732

(a) Includes securities issued and guaranteed by U.S. and non-U.S. governments, and securities issued by governmental agencies and municipalities.

(b) Comprised of U.S. residential and commercial mortgage-backed securities.

(c) Includes certain investments that have been valued using the net asset value (NAV) practical expedient, and therefore have not been categorized in the fair value hierarchy. The inclusion of such amounts in the above table is intended to aid reconciliation of investments categorized in the fair value hierarchy to total pension plan assets.

The following describes the financial assets of the funded pension plans:

Cash and short-term investment funds - Consists of cash on hand and short-term investment funds that provide for daily investments and redemptions which are classified as Level 1.

Equities - Consists of individually held U.S. and international equity securities. This investment category also includes funds that consist primarily of U.S. and international equity securities. Equity securities, which are individually held and are traded actively on exchanges, are classified as Level 1. Certain funds, consisting primarily of equity securities, are classified as Level 2 if the NAV is determined and published daily, and is the basis for current transactions. Commingled funds, consisting primarily of equity securities, are valued using the NAV per fund share.

Fixed income investments - Consists of individually held securities issued by the U.S. government, non-U.S. governments, governmental agencies, municipalities and corporations, and agency and non-agency mortgage backed securities. This investment category also includes funds that consist of fixed income securities. Individual fixed income securities are generally priced based on

evaluated prices from independent pricing services, which are monitored and provided by the third-party custodial firm responsible for safekeeping assets of the particular plan and are classified as Level 2. Certain funds, consisting primarily of fixed income securities, are classified as Level 2 if the NAV is determined and published daily, and is the basis for current transactions. Commingled funds, consisting primarily of fixed income securities, are valued using the NAV per fund share.

Other investments - Consists of exchange-traded real estate investment trust securities, which are classified as Level 1. Commingled funds and limited partnership investments in hedge funds, private equity and real estate funds are valued at the NAV per fund share.

Contributions and estimated future benefit payments: To preserve cash in 2021, we are minimizing non-required cash contributions to funded pension plans. In 2021, we expect to contribute approximately \$4 million to our funded pension plans.

Estimated future benefit payments by the funded and unfunded pension plans, and the postretirement medical plan, which reflect expected future service, are as follows (in millions):

2021	\$	151
2022		134
2023		133
2024		137
2025		130
Years 2026 to 2030		687

We also have defined contribution plans for certain eligible employees. Employees may contribute a portion of their compensation to these plans and we match a portion of the employee contributions. We recorded expense of \$22 million in 2020 for contributions to these plans (2019: \$20 million; 2018: \$19 million).

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10. Revenue

Revenue from contracts with customers on a disaggregated basis was as follows (in millions):

	Exploration and Production					Midstream	Eliminations	Total
	United States	Guyana	Malaysia and JDA	Other (a)	E&P Total			
2020								
Sales of our net production volumes:								
Crude oil revenue	\$ 1,898	\$ 278	\$ 34	\$ 153	\$ 2,363	\$ —	\$ —	\$ 2,363
Natural gas liquids revenue	253	—	—	—	253	—	—	253
Natural gas revenue	144	—	477	10	631	—	—	631
Sales of purchased oil and gas	831	5	—	11	847	—	—	847
Intercompany revenue	—	—	—	—	—	1,092	(1,092)	—
Total revenues from contracts with customers	3,126	283	511	174	4,094	1,092	(1,092)	4,094
Other operating revenues (b)	478	67	—	28	573	—	—	573
Total sales and other operating revenues	\$ 3,604	\$ 350	\$ 511	\$ 202	\$ 4,667	\$ 1,092	\$ (1,092)	\$ 4,667
2019								
Sales of our net production volumes:								
Crude oil revenue	\$ 2,981	\$ —	\$ 113	\$ 566	\$ 3,660	\$ —	\$ —	\$ 3,660
Natural gas liquids revenue	229	—	—	—	229	—	—	229
Natural gas revenue	150	—	646	33	829	—	—	829
Sales of purchased oil and gas	1,644	—	3	91	1,738	—	—	1,738
Intercompany revenue	—	—	—	—	—	848	(848)	—
Total revenues from contracts with customers	5,004	—	762	690	6,456	848	(848)	6,456
Other operating revenues (b)	39	—	—	—	39	—	—	39
Total sales and other operating revenues	\$ 5,043	\$ —	\$ 762	\$ 690	\$ 6,495	\$ 848	\$ (848)	\$ 6,495
2018								
Sales of our net production volumes:								
Crude oil revenue	\$ 2,832	\$ —	\$ 104	\$ 587	\$ 3,523	\$ —	\$ —	\$ 3,523
Natural gas liquids revenue	308	—	—	—	308	—	—	308
Natural gas revenue	176	—	651	32	859	—	—	859
Sales of purchased oil and gas	1,661	—	14	93	1,768	—	—	1,768
Intercompany revenue	—	—	—	—	—	713	(713)	—
Total revenues from contracts with customers	4,977	—	769	712	6,458	713	(713)	6,458
Other operating revenues (b)	(135)	—	—	—	(135)	—	—	(135)
Total sales and other operating revenues	\$ 4,842	\$ —	\$ 769	\$ 712	\$ 6,323	\$ 713	\$ (713)	\$ 6,323

(a) Other includes our interests in Denmark and Libya.

(b) Includes gains (losses) on commodity derivatives of \$547 million in 2020, \$1 million in 2019, and \$(183) million in 2018.

11. Dispositions

2020: We completed the sale of our 28% working interest in the Shenzi Field in the deepwater Gulf of Mexico for proceeds of \$482 million, after normal closing adjustments, and recognized a pre-tax gain of \$79 million (\$79 million after income taxes).

2019: We completed the sale of our remaining acreage in the Utica shale play in eastern Ohio for proceeds of \$22 million, after normal closing adjustments, and recognized a pre-tax gain of \$22 million (\$22 million after income taxes).

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2018: We completed the sale of our joint venture interests in the Utica shale play in eastern Ohio for proceeds of \$396 million, after normal closing adjustments, and recognized a pre-tax gain of \$14 million (\$14 million after income taxes). In addition, we completed the sale of our interests in Ghana for total consideration of \$100 million, consisting of a \$25 million payment that was received at closing and a further payment of \$75 million that is payable to us upon the buyer receiving government approval for a Plan of Development on the Deepwater Tano Cape Three Points Block. The receipt of proceeds at closing resulted in a pre-tax gain of \$10 million (\$10 million after income taxes).

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12. Impairment

Oil and Gas Properties:

As a result of the significant decline in crude oil prices due to the global economic slowdown from the COVID-19 pandemic, we reviewed our oil and gas properties within the Exploration and Production operating segment for impairment in the first quarter of 2020. We recognized pre-tax impairment charges in the first quarter of 2020 to reduce the carrying value of our oil and gas properties and certain related right-of-use assets at the North Malay Basin in Malaysia by \$755 million (\$755 million after income taxes), the South Arne Field in Denmark by \$670 million (\$594 million after income taxes), and in the Gulf of Mexico, the Stampede Field by \$410 million (\$410 million after income taxes) and the Tubular Bells Field by \$270 million (\$270 million after income taxes) primarily as a result of a lower long-term crude oil price outlook. The impairment charges were based on estimates of fair value at March 31, 2020 determined by discounting internally developed future net cash flows, a Level 3 fair value measurement. The total of the fair value estimates was approximately \$1.05 billion. Significant inputs used in determining the discounted future net cash flows include future prices, projected production volumes using risk adjusted oil and gas reserves, and discount rates. The future pricing assumptions used were based on forward strip crude oil prices as of March 31, 2020 for the remainder of 2020 through 2022, and \$50 per barrel for WTI (\$55 per barrel for Brent) in 2023 and thereafter to the end of field life. The weighted average crude oil benchmark price based on total projected crude oil volumes for the impaired assets was \$48.82 per barrel. A discount rate of 10% was used in each of the fair value measurements which represents the estimated discount rate a market participant would use. We determined the discount rate by considering the weighted average cost of capital for a group of peer companies.

Other Assets:

In the first quarter of 2020, we recognized impairment charges totaling \$21 million pre-tax (\$20 million after income taxes) related to drilling rig right-of-use assets in the Bakken and surplus materials and supplies.

13. Exit and Disposal Costs

We incurred employee termination costs of \$27 million in 2020 and \$38 million in 2018 related to cost reduction initiatives and asset sales in 2018. All charges were based on amounts incurred under ongoing severance arrangements or other statutory requirements, plus amounts earned under enhanced benefit arrangements. Payments for termination costs were \$20 million in 2020 (2019: \$4 million; 2018: \$40 million).

14. Share-based Compensation

We have established and maintain long term incentive plans (LTIP) for the granting of restricted common shares, performance share units (PSUs) and stock options to our employees. At December 31, 2020, the total number of authorized common stock under the LTIP was 51.5 million shares, of which we have 13.0 million shares available for issuance. Share-based compensation expense consisted of the following:

	2020	2019	2018
	(In millions)		
Restricted stock	\$ 51	\$ 53	\$ 40
Performance share units	18	22	22
Stock options	10	10	10
Share-based compensation expense before income taxes	\$ 79	\$ 85	\$ 72
Income tax benefit on share-based compensation expense	\$ —	\$ —	\$ —

Based on share-based compensation awards outstanding at December 31, 2020, unearned compensation expense, before income taxes, will be recognized in future years as follows (in millions): 2021: \$49, 2022: \$26 and 2023: \$4.

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Our share-based compensation plans can be summarized as follows:

Restricted stock:

Restricted stock generally vests equally on an annual basis over a three-year term and is valued based on the prevailing market price of our common stock on the date of grant. The following is a summary of restricted stock award activity in 2020:

	Shares of Restricted Common Stock	Weighted - Average Price on Date of Grant
	(In thousands, except per share amounts)	
Outstanding at January 1, 2020	2,014	\$ 53.61
Granted	1,122	49.71
Vested (a)	(1,028)	52.67
Forfeited	(191)	52.54
Outstanding at December 31, 2020	<u>1,917</u>	<u>\$ 51.94</u>

(a) In 2020, restricted stock with fair values of \$51 million were vested (2019: \$102 million; 2018: \$54 million).

Performance share units:

PSUs generally vest three years from the date of grant and are valued using a Monte Carlo simulation on the date of grant. The number of shares of common stock to be issued under a PSU agreement is based on a comparison of the Corporation's total shareholder return (TSR) to the TSR of a predetermined group of peer companies over a three-year performance period ending December 31 of the year prior to settlement of the grant. Beginning with the PSUs granted in 2020, the Corporation's TSR is compared to the TSR of a predetermined group of peer companies and the S&P 500 index over the three-year performance period. Payouts of the performance share awards will range from 0% to 200% of the target awards based on the Corporation's TSR ranking within the peer group. Dividend equivalents for the performance period will accrue on performance shares but will only be paid out on earned shares after the performance period. The following is a summary of PSU activity in 2020:

	Performance Share Units	Weighted - Average Fair Value on Date of Grant
	(In thousands, except per share amounts)	
Outstanding at January 1, 2020	929	\$ 59.57
Granted	308	58.14
Vested (a)	(416)	52.86
Forfeited	(15)	66.63
Outstanding at December 31, 2020	<u>806</u>	<u>\$ 62.36</u>

(a) In 2020, PSU's with fair value of \$48 million were vested (2019: \$16 million; 2018: \$9 million).

The following weighted average assumptions were utilized to estimate the fair value of PSU awards:

	2020	2019	2018
Risk free interest rate	0.52 %	2.48 %	2.39 %
Stock price volatility	0.374	0.369	0.400
Contractual term in years	3.0	3.0	3.0
Grant date price of Hess common stock	\$ 49.72	\$ 56.74	\$ 48.48

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Stock options:

Stock options vest over three years from the date of grant, have a 10-year term, and the exercise price equals the market price of our common stock on the date of grant. The following is a summary of stock options activity in 2020:

	Number of options (In thousands)	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term
Outstanding at January 1, 2020	4,301	\$ 63.24	4.8 years

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Granted	686	49.72	
Exercised	(261)	59.88	
Cancelled	(301)	61.13	
Forfeited	(43)	52.70	
Outstanding at December 31, 2020	<u>4,382</u>	<u>\$ 61.57</u>	5.1 years

At December 31, 2020, there were 4.4 million outstanding stock options (3.2 million exercisable) with a weighted average remaining contractual life of 5.1 years (3.8 years for exercisable options) and an aggregated intrinsic value of \$9.3 million (\$6.3 million for exercisable options).

The following weighted average assumptions were utilized to estimate the fair value of stock options:

	<u>2020</u>	<u>2019</u>	<u>2018</u>
Risk free interest rate	0.64 %	2.55 %	2.74 %
Stock price volatility	0.372	0.359	0.322
Dividend yield	2.01 %	1.76 %	2.06 %
Expected life in years	6.0	6.0	6.0
Weighted average fair value per option granted	\$ 14.30	\$ 18.08	\$ 13.69

In estimating the fair value of PSUs and stock options, the risk-free interest rate is based on the vesting period of the award and is obtained from published sources. The stock price volatility is determined from the historical stock prices of the Corporation using the expected term.

15. Income Taxes

The provision (benefit) for income taxes consisted of:

	<u>2020</u>	<u>2019</u>	<u>2018</u>
	(In millions)		
United States			
Federal			
Current	\$ (4)	\$ (1)	\$ 1
Deferred taxes and other accruals	6	72	(74)
State	(1)	16	(45)
	<u>1</u>	<u>87</u>	<u>(118)</u>
Foreign			
Current (a)	48	447	455
Deferred taxes and other accruals	(60)	(73)	(2)
	<u>(12)</u>	<u>374</u>	<u>453</u>
Provision (Benefit) For Income Taxes	<u>\$ (11)</u>	<u>\$ 461</u>	<u>\$ 335</u>

(a) Primarily comprised of Libya in 2019 and 2018.

Income (loss) before income taxes consisted of the following:

	<u>2020</u>	<u>2019</u>	<u>2018</u>
	(In millions)		
United States (a)	\$ (1,509)	\$ (338)	\$ (219)
Foreign	(1,341)	559	439
Income (Loss) Before Income Taxes	<u>\$ (2,850)</u>	<u>\$ 221</u>	<u>\$ 220</u>

(a) Includes substantially all of our interest expense, corporate expense and the results of commodity hedging activities.

The difference between our effective income tax rate and the U.S. statutory rate is reconciled below:

	<u>2020</u>	<u>2019</u>	<u>2018</u>
U.S. statutory rate	21.0 %	21.0 %	21.0 %
Effect of foreign operations (a)	12.1	142.9	141.2
State income taxes, net of federal income tax	0.1	5.8	(18.9)
Valuation allowance on current year operations	(36.5)	41.8	55.2
Release valuation allowance against previously unbenefited deferred tax assets	—	(24.5)	—
Noncontrolling interests in Midstream	1.7	(16.0)	(15.9)

Intraperiod allocation	—	33.7	(37.3)
Credits	2.0	—	—
Equity and executive compensation	(0.1)	2.2	7.4
Other	0.1	1.2	(0.3)
Total	0.4 %	208.1 %	152.4 %

(a) The variance in effective income tax rates attributable to the effect of foreign operations primarily resulted from the mix of income among high, primarily Libya, and low tax rate jurisdictions.

The components of deferred tax liabilities and deferred tax assets at December 31, were as follows:

	2020	2019
	(In millions)	
Deferred Tax Liabilities		
Property, plant and equipment and investments	\$ (847)	\$ (1,318)
Other	(45)	(45)
Total Deferred Tax Liabilities	(892)	(1,363)
Deferred Tax Assets		
Net operating loss carryforwards	5,037	4,733
Tax credit carryforwards	135	66
Property, plant and equipment and investments	55	206
Accrued compensation, deferred credits and other liabilities	196	179
Asset retirement obligations	252	261
Other	325	317
Total Deferred Tax Assets	6,000	5,762
Valuation allowances (a)	(5,391)	(4,734)
Total deferred tax assets, net of valuation allowances	609	1,028
Net Deferred Tax Assets (Liabilities)	\$ (283)	\$ (335)

(a) In 2020, the valuation allowance increased by \$657 million (2019: decrease of \$143 million; 2018: decrease of \$322 million).

In the *Consolidated Balance Sheet*, deferred tax assets and liabilities are netted by taxing jurisdiction and are recorded at December 31, as follows:

	2020	2019
	(In millions)	
Deferred income taxes (long-term asset)	\$ 59	\$ 80
Deferred income taxes (long-term liability)	(342)	(415)
Net Deferred Tax Assets (Liabilities)	\$ (283)	\$ (335)

At December 31, 2020, we have recognized a gross deferred tax asset related to net operating loss carryforwards of \$5,037 million before application of valuation allowances. The deferred tax asset is comprised of \$1,121 million attributable to foreign net operating losses which begin to expire in 2025, \$3,277 million attributable to U.S. federal operating losses which begin to expire in 2034, and \$639 million attributable to losses in various U.S. states which begin to expire in 2021. The deferred tax asset attributable to foreign net operating losses, net of valuation allowances, is \$155 million. A full valuation allowance is established against the deferred tax asset attributable to U.S. federal and state net operating losses, except for \$3 million U.S. federal and \$1 million U.S. state deferred tax asset attributable to Midstream activities. At December 31, 2020, we have U.S. federal, state and foreign alternative minimum tax credit carryforwards of \$49 million, which can be carried forward indefinitely, and approximately \$83 million of other business credit carryforwards. The deferred tax asset attributable to these credits, net of valuation allowances was not significant. A full valuation allowance is established against our foreign tax credit carryforwards of \$3 million, which begin to expire in 2021.

At December 31, 2020, the *Consolidated Balance Sheet* reflects a \$5,391 million valuation allowance against the net deferred tax assets for multiple jurisdictions based on application of the relevant accounting standards. Hess continues to maintain a full valuation

allowance against its deferred tax assets in the U.S., Denmark, and Malaysia. Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. The cumulative loss incurred over the three-year period ending December 31, 2020 constitutes significant objective negative evidence. Such objective negative evidence limits our ability to consider subjective positive evidence, such as our projections of future taxable income, resulting in the recognition of a valuation allowance against the net deferred tax assets for these jurisdictions. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income change or if objective negative evidence in the form of cumulative losses is no longer present and additional weight can be given to subjective evidence. At December 31, 2019 the valuation allowance established against the net deferred tax asset in Guyana

for the Stabroek Block was released as a result of the positive evidence from first production in December 2019, and the significant forecasted pre-tax income from operations. The cumulative pre-tax losses in Guyana were driven by pre-production activities.

Below is a reconciliation of the gross beginning and ending amounts of unrecognized tax benefits:

	2020	2019	2018
	(In millions)		
Balance at January 1	\$ 168	\$ 168	\$ 205
Additions based on tax positions taken in the current year	2	2	19
Additions based on tax positions of prior years	1	1	36
Reductions based on tax positions of prior years	(2)	(1)	(78)
Reductions due to settlements with taxing authorities	(1)	—	(10)
Reductions due to lapses in statutes of limitation	(2)	(2)	(4)
Balance at December 31	\$ 166	\$ 168	\$ 168

The December 31, 2020 balance of unrecognized tax benefits includes \$16 million that, if recognized, would impact our effective income tax rate. Over the next 12 months, it is reasonably possible that the total amount of unrecognized tax benefits could decrease between zero and \$41 million due to settlements with taxing authorities or other resolutions, as well as lapses in statutes of limitation. At December 31, 2020, our accrued interest and penalties related to unrecognized tax benefits is \$6 million (2019: \$7 million).

We file income tax returns in the U.S. and various foreign jurisdictions. We are no longer subject to examinations by income tax authorities in most jurisdictions for years prior to 2010.

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16. Outstanding and Weighted Average Common Shares

The Net income (loss) and weighted average number of common shares used in basic and diluted earnings per share computation were as follows:

	2020	2019	2018
	(In millions except per share amounts)		
Net Income (Loss) Attributable to Hess Corporation Common Stockholders:			
Net income (loss)	\$ (2,839)	\$ (240)	\$ (115)
Less: Net income (loss) attributable to noncontrolling interests	254	168	167
Less: Preferred stock dividends	—	4	46
Net income (loss) attributable to Hess Corporation Common Stockholders	<u>\$ (3,093)</u>	<u>\$ (412)</u>	<u>\$ (328)</u>
Weighted Average Number of Common Shares Outstanding:			
Basic	304.8	301.2	298.2
Effect of dilutive securities			
Restricted common stock	—	—	—
Stock options	—	—	—
Performance share units	—	—	—
Mandatory convertible preferred stock	—	—	—
Diluted	<u>304.8</u>	<u>301.2</u>	<u>298.2</u>
Net Income (Loss) Attributable to Hess Corporation per Common Share:			
Basic	\$ (10.15)	\$ (1.37)	\$ (1.10)
Diluted	\$ (10.15)	\$ (1.37)	\$ (1.10)
Antidilutive shares excluded from the computation of diluted shares:			
Restricted common stock	2.1	2.2	2.9
Stock options	4.3	4.7	5.5
Performance share units	1.1	1.7	1.1
Common shares from conversion of preferred stock	—	—	12.7

The following table provides the changes in our outstanding common shares:

2020	2019	2018
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	(In millions)		
Balance at January 1	304.9	291.4	315.1
Conversion of preferred stock	—	11.6	—
Activity related to restricted stock awards, net	1.0	0.9	0.8
Stock options exercised	0.3	0.7	0.6
PSUs vested	0.8	0.3	0.1
Shares repurchased	—	—	(25.2)
Balance at December 31	<u>307.0</u>	<u>304.9</u>	<u>291.4</u>

Preferred Stock Issuance:

In February 2016, we issued depository shares representing 575,000 shares of 8% Series A Mandatory Convertible Preferred Stock (Preferred Stock), par value \$1 per share, with a liquidation preference of \$1,000 per share. On January 31, 2019, the Preferred Stock automatically converted into shares of common stock and the net number of common shares issued by the Corporation was approximately 11.6 million shares.

Common Stock Repurchase Plan:

In 2018, we repurchased 25.2 million shares of our common stock for \$1,380 million at an average cost per share of \$54.85. At December 31, 2020, we are authorized, but not required, to purchase additional common stock up to a value of \$650 million.

Common Stock Dividends:

In 2020, 2019 and 2018, cash dividends declared on common stock totaled \$1.00 per share (\$0.25 per quarter).

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17. Supplementary Cash Flow Information

The following information supplements the *Statement of Consolidated Cash Flows*:

	2020	2019	2018
	(In millions)		
Cash Flows From Operating Activities			
Interest paid	\$ (460)	\$ (380)	\$ (394)
Net income taxes (paid) refunded	(64)	(417)	(463)
Cash Flows From Investing Activities			
Additions to property, plant and equipment - E&P:			
Capital expenditures incurred - E&P	\$ (1,678)	\$ (2,576)	\$ (1,909)
Increase (decrease) in related liabilities	(218)	143	55
Additions to property, plant and equipment - E&P	<u>\$ (1,896)</u>	<u>\$ (2,433)</u>	<u>\$ (1,854)</u>
Additions to property, plant and equipment - Midstream:			
Capital expenditures incurred - Midstream	\$ (253)	\$ (416)	\$ (271)
Increase (decrease) in related liabilities	(48)	20	28
Additions to property, plant and equipment - Midstream	<u>\$ (301)</u>	<u>\$ (396)</u>	<u>\$ (243)</u>

In December 2019, as part of HESM Opco's acquisition of HIP (see *Note 4, Hess Midstream LP*), HESM Opco assumed \$800 million of outstanding HIP notes (see *Note 7, Debt*).

18. Guarantees, Contingencies and Commitments

Guarantees and Contingencies

We are subject to loss contingencies with respect to various claims, lawsuits and other proceedings. A liability is recognized in our consolidated financial statements when it is probable that a loss has been incurred and the amount can be reasonably estimated. If the risk of loss is probable, but the amount cannot be reasonably estimated or the risk of loss is only reasonably possible, a liability is not accrued; however, we disclose the nature of those contingencies. We cannot predict with certainty if, how or when existing claims, lawsuits and proceedings will be resolved or what the eventual relief, if any, may be, particularly for proceedings that are in their early stages of development or where plaintiffs seek indeterminate damages.

We, along with many companies that have been or continue to be engaged in refining and marketing of gasoline, have been a party to lawsuits and claims related to the use of MTBE in gasoline. A series of similar lawsuits, many involving water utilities or governmental entities, were filed in

jurisdictions across the U.S. against producers of MTBE and petroleum refiners who produced gasoline containing MTBE, including us. The principal allegation in all cases was that gasoline containing MTBE was a defective product and that these producers and refiners are strictly liable in proportion to their share of the gasoline market for damage to groundwater resources and are required to take remedial action to ameliorate the alleged effects on the environment of releases of MTBE. The majority of the cases asserted against us have been settled. There are three remaining active cases, filed by Pennsylvania, Rhode Island, and Maryland. In June 2014, the Commonwealth of Pennsylvania filed a lawsuit alleging that we and all major oil companies with operations in Pennsylvania, have damaged the groundwater by introducing thereto gasoline with MTBE. The Pennsylvania suit has been forwarded to the existing MTBE multidistrict litigation pending in the Southern District of New York. In September 2016, the State of Rhode Island also filed a lawsuit alleging that we and other major oil companies damaged the groundwater in Rhode Island by introducing thereto gasoline with MTBE. The suit filed in Rhode Island is proceeding in federal court. In December 2017, the State of Maryland filed a lawsuit alleging that we and other major oil companies damaged the groundwater in Maryland by introducing thereto gasoline with MTBE. The suit, filed in Maryland state court, was served on us in January 2018 and has been removed to federal court by the defendants.

In September 2003, we received a directive from the New Jersey Department of Environmental Protection (NJDEP) to remediate contamination in the sediments of the Lower Passaic River. The NJDEP is also seeking natural resource damages. The directive, insofar as it affects us, relates to alleged releases from a petroleum bulk storage terminal in Newark, New Jersey we previously owned. We and over 70 companies entered into an Administrative Order on Consent with the EPA to study the same contamination; this work remains ongoing. We and other parties settled a cost recovery claim by the State of New Jersey and agreed with the EPA to fund remediation of a portion of the site. On March 4, 2016, the EPA issued a Record of Decision (ROD) in respect of the lower eight miles of the Lower Passaic River, selecting a remedy that includes bank-to-bank dredging at an estimated cost of \$1.38 billion. The ROD does not address the upper nine miles of the Lower Passaic River or the Newark Bay, which may require additional remedial action. In addition, the federal trustees for natural resources have begun a separate assessment of damages to natural resources in the Passaic River. Given that the EPA has not selected a remedy for the entirety of the Lower Passaic River or the Newark Bay, total

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remedial costs cannot be reliably estimated at this time. Based on currently known facts and circumstances, we do not believe that this matter will result in a significant liability to us because our former terminal did not store or use contaminants which are of concern in the river sediments and could not have contributed contamination along the river's length. Further, there are numerous other parties who we expect will bear the cost of remediation and damages.

In March 2014, we received an Administrative Order from the EPA requiring us and 26 other parties to undertake the Remedial Design for the remedy selected by the EPA for the Gowanus Canal Superfund Site in Brooklyn, New York. Our alleged liability derives from our former ownership and operation of a fuel oil terminal and connected shipbuilding and repair facility adjacent to the Canal. The remedy selected by the EPA includes dredging of surface sediments and the placement of a cap over the deeper sediments throughout the Canal and in-situ stabilization of certain contaminated sediments that will remain in place below the cap. The EPA's original estimate was that this remedy would cost \$506 million; however, the ultimate costs that will be incurred in connection with the design and implementation of the remedy remain uncertain. We have complied with the EPA's March 2014 Administrative Order and contributed funding for the Remedial Design based on an allocation of costs among the parties determined by a third-party expert. In January 2020, we received an additional Administrative Order from the EPA requiring us and several other parties to begin Remedial Action along the uppermost portion of the Canal. We intend to comply with this Administrative Order. The remediation work began in the fourth quarter of 2020. Based on currently known facts and circumstances, we do not believe that this matter will result in a significant liability to us, and the costs will continue to be allocated amongst the parties, as they were for the Remedial Design.

From time to time, we are involved in other judicial and administrative proceedings relating to environmental matters. We periodically receive notices from the EPA that we are a "potential responsible party" under the Superfund legislation with respect to various waste disposal sites. Under this legislation, all potentially responsible parties may be jointly and severally liable. For any site for which we have received such a notice, the EPA's claims or assertions of liability against us relating to these sites have not been fully developed, or the EPA's claims have been settled or a settlement is under consideration, in all cases for amounts that are not material. Beginning in 2017, certain states, municipalities and private associations in California, Delaware, Maryland, Rhode Island and South Carolina separately filed lawsuits against oil, gas and coal producers, including us, for alleged damages purportedly caused by climate change. These proceedings include claims for monetary damages and injunctive relief. Beginning in 2013, various parishes in Louisiana filed suit against approximately 100 oil and gas companies, including us, alleging that the companies' operations and activities in certain fields violated the State and Local Coastal Resource Management Act of 1978, as amended, and caused contamination, subsidence and other environmental damages to land and water bodies located in the coastal zone of Louisiana. The plaintiffs seek, among other things, the payment of the costs necessary to clear, re-vegetate and otherwise restore the allegedly impacted areas. The ultimate impact of the aforementioned proceedings, and of any related proceedings by private parties, on our business or accounts cannot be predicted at this time due to the large number of other potentially responsible parties and the speculative nature of clean-up cost estimates.

We are also involved in other judicial and administrative proceedings from time to time in addition to the matters described above, including claims related to post-production deductions from royalty payments. We cannot predict with certainty if, how or when such proceedings will be resolved or what the eventual relief, if any, may be, particularly for proceedings that are in their early stages of development or where plaintiffs seek indeterminate damages. Numerous issues may need to be resolved, including through potentially lengthy discovery and determination of important factual matters before a loss or range of loss can be reasonably estimated for any proceeding.

Subject to the foregoing, in management's opinion, based upon currently known facts and circumstances, the outcome of lawsuits, claims and proceedings, including the matters disclosed above, is not expected to have a material adverse effect on our financial condition, results of

operations or cash flows. However, we could incur judgments, enter into settlements, or revise our opinion regarding the outcome of certain matters, and such developments could have a material adverse effect on our results of operations in the period in which the amounts are accrued and our cash flows in the period in which the amounts are paid.

Unconditional Purchase Obligations and Commitments

The following table shows aggregate information for certain unconditional purchase obligations and commitments at December 31, 2020, which are not included elsewhere within these *Consolidated Financial Statements*:

	Total	Payments Due by Period			
		2022 and 2023	2024 and 2025	Thereafter	
		(In millions)			
Capital expenditures	\$ 2,837	\$ 868	\$ 1,469	\$ 500	\$ —
Operating expenses	236	167	63	5	1
Transportation and related contracts	2,867	310	756	493	1,308

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19. Segment Information

We currently have two operating segments, E&P and Midstream. The E&P operating segment explores for, develops, produces, purchases and sells crude oil, NGL and natural gas. Production operations over the three years ended December 31, 2020 were in the United States (U.S.), Malaysia and the JDA, Denmark, Libya, and Guyana commencing December 2019. The Midstream operating segment provides fee-based services including crude oil and natural gas gathering, processing of natural gas and the fractionation of NGL, transportation of crude oil by rail car, terminaling and loading crude oil and NGL, storing and terminaling propane, and water handling services primarily in the Bakken shale play of North Dakota. All unallocated costs are reflected under Corporate, Interest and Other.

The following table presents operating segment financial data (in millions):

	Exploration and Production	Midstream	Corporate, Interest and Other	Eliminations	Total
2020					
Sales and Other Operating Revenues - Third parties	\$ 4,667	\$ —	\$ —	\$ —	\$ 4,667
Intersegment Revenues	—	1,092	—	(1,092)	—
Sales and Other Operating Revenues	\$ 4,667	\$ 1,092	\$ —	\$ (1,092)	\$ 4,667
Net Income (Loss) Attributable to Hess Corporation	\$ (2,841)	\$ 230	\$ (482)	\$ —	\$ (3,093)
Interest Expense	—	95	373	—	468
Depreciation, Depletion and Amortization	1,915	157	2	—	2,074
Impairment	2,126	—	—	—	2,126
Provision (Benefit) for Income Taxes (a)	(12)	7	(6)	—	(11)
Investment in Affiliates	104	108	—	—	212
Identifiable Assets	13,688	3,599	1,534	—	18,821
Capital Expenditures	1,678	253	—	—	1,931
2019					
Sales and Other Operating Revenues - Third parties	\$ 6,495	\$ —	\$ —	\$ —	\$ 6,495
Intersegment Revenues	—	848	—	(848)	—
Sales and Other Operating Revenues	\$ 6,495	\$ 848	\$ —	\$ (848)	\$ 6,495
Net Income (Loss) Attributable to Hess Corporation	\$ 53	\$ 144	\$ (605)	\$ —	\$ (408)
Interest Expense	—	63	317	—	380
Depreciation, Depletion and Amortization	1,977	142	3	—	2,122
Provision (Benefit) for Income Taxes (a)	375	—	86	—	461
Investment in Affiliates	114	108	—	—	222
Identifiable Assets	16,790	3,499	1,493	—	21,782
Capital Expenditures	2,576	416	—	—	2,992
2018					
Sales and Other Operating Revenues - Third parties	\$ 6,323	\$ —	\$ —	\$ —	\$ 6,323

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Intersegment Revenues	—	713	—	(713)	—
Sales and Other Operating Revenues	\$ 6,323	\$ 713	\$ —	\$ (713)	\$ 6,323
Net Income (Loss) Attributable to Hess Corporation	\$ 51	\$ 120	\$ (453)	\$ —	\$ (282)
Interest Expense	—	60	339	—	399
Depreciation, Depletion and Amortization	1,748	127	8	—	1,883
Provision (Benefit) for Income Taxes (a)	391	38	(94)	—	335
Capital Expenditures	1,909	271	—	—	2,180

(a) Commencing January 1, 2019, management changed its measurement of segment earnings to reflect income taxes on a post U.S. tax consolidation and valuation allowance assessment basis. In 2018, the provision for income taxes in the Midstream segment was presented before consolidating its operations with other U.S. activities of the Corporation and prior to evaluating realizability of net U.S. deferred taxes. An offsetting impact was presented in the E&P segment. If 2018 segment results were prepared on a basis consistent with 2020 and 2019, Midstream segment net income attributable to Hess Corporation would have been \$158 million and E&P net income attributable to Hess Corporation would have been \$13 million.

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The following table presents financial information by major geographic area:

	United States	Guyana	Malaysia and JDA	Other	Corporate, Interest and other	Total
	(In millions)					
2020						
Sales and Other Operating Revenues	\$ 3,604	\$ 350	\$ 511	\$ 202	\$ —	\$ 4,667
Property, Plant and Equipment (Net) (a)	10,384	2,114	1,067	539	11	14,115
2019						
Sales and Other Operating Revenues	\$ 5,043	\$ —	\$ 762	\$ 690	\$ —	\$ 6,495
Property, Plant and Equipment (Net) (a)	12,182	1,507	1,890	1,223	12	16,814
2018						
Sales and Other Operating Revenues	\$ 4,842	\$ —	\$ 769	\$ 712	\$ —	\$ 6,323

(a) Property, plant and equipment in the United States, in 2020, includes \$7,273 million (2019: \$9,172 million) attributable to the E&P segment and \$3,111 million (2019: \$3,010 million) attributable to the Midstream segment.

20. Financial Risk Management Activities

In the normal course of our business, we are exposed to commodity risks related to changes in the prices of crude oil and natural gas, as well as changes in interest rates and foreign currency values. In the disclosures that follow, corporate financial risk management activities refer to the mitigation of these risks through hedging activities. We maintain a control environment for all of our financial risk management activities under the direction of our Chief Risk Officer. Our Treasury department is responsible for administering foreign exchange rate and interest rate hedging programs using similar controls and processes, where applicable. Hedging strategies are reviewed annually by the Audit Committee of the Board of Directors.

Corporate Financial Risk Management Activities: Financial risk management activities include transactions designed to reduce risk in the selling prices of crude oil or natural gas we produce or by reducing our exposure to foreign currency or interest rate movements. Generally, futures, swaps or option strategies may be used to fix the forward selling price of a portion of our crude oil or natural gas production. Swaps may also be used to fix the difference between current selling prices and forward selling prices in periods of contango for crude oil production that will be stored and sold in the future. Forward contracts may also be used to purchase certain currencies in which we conduct business with the intent of reducing exposure to foreign currency fluctuations. At December 31, 2020, these forward contracts relate to the British Pound, Danish Krone, Canadian Dollar and Malaysian Ringgit. Interest rate swaps may be used to convert interest payments on certain long-term debt from fixed to floating rates.

The notional amounts of outstanding financial risk management derivative contracts were as follows:

	December 31, 2020	December 31, 2019
	(In millions)	
Commodity - crude oil put options (millions of barrels)	27.4	54.9
Foreign exchange forwards	\$ 163	\$ 90
Interest rate swaps	\$ 100	\$ 100

At December 31, 2020, we had WTI put options with an average monthly floor price of approximately \$45 per barrel for 75,000 bopd for 2021. In the first quarter of 2021, we increased the average monthly floor price of 75,000 bopd of WTI put option contracts from approximately \$45 per barrel to \$50 per barrel for the remainder of 2021. We also purchased additional WTI put options with an average monthly floor price of \$50 per barrel for 45,000 bopd and Brent put options with an average monthly floor price of \$55 per barrel for 30,000 bopd. As a result, we now have total purchased WTI put options of 120,000 bopd with an average monthly floor price of \$50 per barrel and total purchased Brent put options of 30,000 bopd with

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an average monthly floor price of \$55 per barrel for the remainder of 2021.

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The table below reflects the gross and net fair values of risk management derivative instruments:

	Assets	Liabilities
	(In millions)	
<u>December 31, 2020</u>		
Derivative Contracts Designated as Hedging Instruments:		
Crude oil put options	\$ 64	\$ —
Crude oil swaps	—	(54)
Interest rate swaps	5	—
Total derivative contracts designated as hedging instruments	69	(54)
Derivative Contracts Not Designated as Hedging Instruments:		
Foreign exchange forwards	—	(1)
Total derivative contracts not designated as hedging instruments	—	(1)
Gross fair value of derivative contracts	69	(55)
Gross amount offset in the Consolidated Balance Sheet	(13)	13
Net Amounts Presented in the Consolidated Balance Sheet	\$ 56	\$ (42)
<u>December 31, 2019</u>		
Derivative Contracts Designated as Hedging Instruments:		
Crude oil put options	\$ 125	\$ —
Interest rate swaps	1	—
Total derivative contracts designated as hedging instruments	126	—
Derivative Contracts Not Designated as Hedging Instruments:		
Foreign exchange forwards	—	(1)
Total derivative contracts not designated as hedging instruments	—	(1)
Gross fair value of derivative contracts	126	(1)
Gross amount offset in the Consolidated Balance Sheet	—	—
Net Amounts Presented in the Consolidated Balance Sheet	\$ 126	\$ (1)

In 2020, we chartered three VLCCs to load and transport a total of 6.3 million barrels of Bakken crude oil for sale in Asian markets. The first VLCC cargo of 2.1 million barrels was sold in September 2020. We have entered into agreements for the sale of the remaining 4.2 million barrels of crude oil in the first quarter of 2021. In connection with this activity, we entered into Brent swap transactions intended to fix the difference between Brent prices in the month of production and the forward Brent price for the expected month of sale. At December 31, 2020, net realized and unrealized losses from the Brent swaps of \$16 million were deferred in *Accumulated other comprehensive income*, and the liability for unrealized losses from the Brent swaps was \$54 million. In addition, total net realized gains from WTI put options associated with the VLCCs of \$40 million were deferred in *Accumulated other comprehensive income* at December 31, 2020.

The fair value of our crude oil put options and crude oil swaps is presented within *Other current assets* and *Accrued liabilities*, respectively, in our *Consolidated Balance Sheet*. The fair value of our interest rate swaps is presented within *Other assets* in our *Consolidated Balance Sheet*. The fair value of our foreign exchange forwards is presented within *Accrued liabilities* in our *Consolidated Balance Sheet*. All fair values in the table above are based on Level 2 inputs.

Derivative contracts designated as hedging instruments:

Crude oil derivatives: In 2020, crude oil price hedging contracts increased Sales and other operating revenues by \$547 million (2019: increase of \$1 million; 2018: decrease of \$161 million). At December 31, 2020, pre-tax deferred gains in *Accumulated other comprehensive income (loss)* related to outstanding crude oil price hedging contracts were \$4 million, of which all will be reclassified into earnings during the next 12 months as the hedged crude oil sales are recognized in earnings.

Interest rate swaps designated as fair value hedges: At December 31, 2020, we had interest rate swaps with gross notional amounts of \$100 million (2019: \$100 million), which were designated as fair value hedges and relate to long-term debt where we have converted interest payments from fixed to floating rates. Changes in the fair value of interest rate swaps and the hedged fixed-rate debt are recorded in *Interest expense* in the *Statement of Consolidated Income*. In 2020, the change in fair value of interest rate swaps was an increase in the asset of \$4 million (2019: \$3 million decrease in liability; 2018: \$1 million increase in liability) with a corresponding adjustment in the carrying value of the hedged fixed-rate debt.

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Derivative contracts not designated as hedging instruments:

Foreign exchange: Total foreign exchange gains and losses were losses of \$6 million in 2020 (2019: gain of \$3 million; 2018: loss of \$5 million) and are reported in *Other, net* in Revenues and non-operating income in the *Statement of Consolidated Income*. A

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component of foreign exchange gains or losses is the result of foreign exchange derivative contracts that are not designated as hedges, which amounted to a gain of \$2 million in 2020 (2019: loss of \$2 million; 2018: loss of \$2 million).

Crude oil collars: In 2018, noncash adjustments to de-designated crude oil price hedging contracts decreased Sales and other operating revenues by \$22 million.

Credit Risk: We are exposed to credit risks that may at times be concentrated with certain counterparties, groups of counterparties or customers. Accounts receivable are generated from a diverse domestic and international customer base. At December 31, 2020, our Accounts receivable were concentrated with the following counterparty industry segments: Integrated companies — 39%, Independent E&P companies — 39%, Refining and marketing companies — 8%, National oil companies — 5%, Storage and transportation companies — 5%, and Others — 4%. We reduce risk related to certain counterparties, where applicable, by using master netting arrangements and requiring collateral, generally cash or letters of credit.

At December 31, 2020, we had outstanding letters of credit totaling \$269 million (2019: \$272 million).

Fair Value Measurement: At December 31, 2020, our total long-term debt, which was substantially comprised of fixed rate debt instruments, had a carrying value of \$8,296 million and a fair value of \$9,647 million, based on Level 2 inputs in the fair value measurement hierarchy. We also have short-term financial instruments, primarily cash equivalents, accounts receivable and accounts payable, for which the carrying value approximated fair value at December 31, 2020 and December 31, 2019.

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**HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTARY OIL AND GAS DATA (UNAUDITED)**

The *Supplementary Oil and Gas Data* that follows is presented in accordance with ASC 932, *Disclosures about Oil and Gas Producing Activities*, and includes (1) costs incurred, capitalized costs and results of operations relating to oil and gas producing activities, (2) net proved oil and gas reserves and (3) a standardized measure of discounted future net cash flows relating to proved oil and gas reserves, including a reconciliation of changes therein.

During the three-year period ended December 31, 2020, we produced crude oil, NGL and natural gas in the United States (U.S.), Malaysia and the JDA, Denmark, Libya, and Guyana commencing December 2019. Exploration and/or development activities were also conducted in certain of these producing areas as well as offshore Suriname and Canada.

Costs Incurred in Oil and Gas Producing Activities

For the Years Ended December 31	United				
	Total	States	Guyana	Malaysia and JDA	Other
	(In millions)				
2020					
Property acquisitions					
Unproved	\$ —	\$ —	\$ —	\$ —	\$ —
Proved	—	—	—	—	—
Exploration	307	169	130	2	6
Production and development capital expenditures (a)	1,567	804	630	106	27
2019					
Property acquisitions					
Unproved	\$ 26	\$ 26	\$ —	\$ —	\$ —
Proved	—	—	—	—	—
Exploration	455	174	239	4	38
Production and development capital expenditures (a)	2,463	1,735	585	114	29

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2018

Property acquisitions					
Unproved	\$ 51	\$ 43	\$ 8	\$ —	\$ —
Proved	43	43	—	—	—
Exploration	442	111	131	32	168
Production and development capital expenditures (a)	1,577	1,239	244	92	2

(a) Includes an increase of \$88 million for asset retirement obligations related to net accruals and revisions in 2020 (2019: \$201 million increase; 2018: \$44 million increase).

Capitalized Costs Relating to Oil and Gas Producing Activities

	At December 31,	
	2020	2019
	(In millions)	
Unproved properties	\$ 164	\$ 168
Proved properties	2,930	3,304
Wells, equipment and related facilities	23,224	28,404
Total costs	26,318	31,876
Less: Reserve for depreciation, depletion, amortization and lease impairment	15,325	18,084
Net Capitalized Costs	\$ 10,993	\$ 13,792

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Results of Operations for Oil and Gas Producing Activities

The results of operations shown below exclude non-oil and gas producing activities, primarily gains (losses) on sales of oil and gas properties, sales of purchased crude oil, NGL and natural gas from third parties, interest expense and non-operating income. Therefore, these results are on a different basis than the net income (loss) from E&P operations reported in Management's Discussion and Analysis of Financial Condition and Results of Operations and in *Note 19, Segment Information* in the *Notes to Consolidated Financial Statements*. Other includes results for Denmark, Libya, Canada and Suriname.

For the Years Ended December 31	United				
	Total	States	Guyana (a)	Malaysia and JDA	Other
	(In millions)				
2020					
Sales and Other Operating Revenues	\$ 3,794	\$ 2,747	\$ 345	\$ 511	\$ 191
Costs and Expenses					
Operating costs and expenses	895	564	136	109	86
Production and severance taxes	124	118	—	6	—
Midstream tariffs	946	946	—	—	—
Exploration expenses, including dry holes and lease impairment	351	284	25	—	42
General and administrative expenses	206	176	9	12	9
Depreciation, depletion and amortization	1,915	1,480	130	268	37
Impairment	2,126	697	—	755	674
Total Costs and Expenses	6,563	4,265	300	1,150	848
Results of Operations Before Income Taxes	(2,769)	(1,518)	45	(639)	(657)
Provision (benefit) for income taxes	(4)	—	9	22	(35)
Results of Operations	\$ (2,765)	\$ (1,518)	\$ 36	\$ (661)	\$ (622)
2019					
Sales and Other Operating Revenues	\$ 4,719	\$ 3,361	\$ —	\$ 759	\$ 599
Costs and Expenses					
Operating costs and expenses	971	693	47	139	92
Production and severance taxes	184	176	—	8	—
Midstream tariffs	722	722	—	—	—
Exploration expenses, including dry holes and lease impairment	233	144	47	3	39
General and administrative expenses	204	176	7	12	9
Depreciation, depletion and amortization	1,977	1,489	1	413	74
Total Costs and Expenses	4,291	3,400	102	575	214

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Results of Operations Before Income Taxes	428	(39)	(102)	184	385
Provision (benefit) for income taxes	325	—	(60)	13	372
Results of Operations	<u>\$ 103</u>	<u>\$ (39)</u>	<u>\$ (42)</u>	<u>\$ 171</u>	<u>\$ 13</u>
2018					
Sales and Other Operating Revenues	<u>\$ 4,515</u>	<u>\$ 3,141</u>	<u>\$ —</u>	<u>\$ 755</u>	<u>\$ 619</u>
Costs and Expenses					
Operating costs and expenses	941	697	24	129	91
Production and severance taxes	171	165	—	6	—
Midstream tariffs	648	648	—	—	—
Exploration expenses, including dry holes and lease impairment	362	119	40	6	197
General and administrative expenses	258	230	4	10	14
Depreciation, depletion and amortization	1,748	1,297	—	395	56
Total Costs and Expenses	<u>4,128</u>	<u>3,156</u>	<u>68</u>	<u>546</u>	<u>358</u>
Results of Operations Before Income Taxes	<u>387</u>	<u>(15)</u>	<u>(68)</u>	<u>209</u>	<u>261</u>
Provision (benefit) for income taxes	337	(63)	—	11	389
Results of Operations	<u>\$ 50</u>	<u>\$ 48</u>	<u>\$ (68)</u>	<u>\$ 198</u>	<u>\$ (128)</u>

(a) Production from Liza Phase 1 commenced in December 2019. Operating costs and expenses also include pre-development costs from the operator for future phases of development and Hess internal costs.

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Proved Oil and Gas Reserves

Our proved oil and gas reserves are calculated in accordance with the Securities and Exchange Commission (SEC) regulations and the requirements of the Financial Accounting Standards Board. Proved oil and gas reserves are quantities, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from known reservoirs under existing economic conditions, operating methods and government regulations. Our estimation of net recoverable quantities of liquid hydrocarbons and natural gas is a highly technical process performed by our internal teams of geoscience and reservoir engineering professionals. Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of June 25, 2019).” The method or combination of methods used in the analysis of each reservoir is based on the maturity of the reservoir, the completeness of the subsurface data available at the time of the estimate, the stage of reservoir development and the production history. Subsurface data used included well logs, reservoir core and fluid samples, production and pressure testing, static and dynamic pressure information, and reservoir surveillance. Where applicable, reliable technologies may be used in reserve estimation, as defined in the SEC regulations. These technologies, including computational methods, must have been field tested and demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. In some cases, where appropriate, use of empirical and analytical methods, combined with analog data were used. Analytic tools, including reservoir simulation, geologic modeling and seismic processing, have been used in the interpretation of the subsurface data. These technologies were used to increase the quality and confidence in the reserves estimates.

In order for reserves to be classified as proved, any required government approvals must be obtained and depending on the cost of the project, either senior management or the Board of Directors must commit to fund the development. Our proved reserves are subject to certain risks and uncertainties, which are discussed in *Item 1A. Risk Factors* of this Form 10-K.

Internal Controls

The Corporation maintains internal controls over its oil and gas reserve estimation processes, which are administered by our Global Reserves group and our Chief Financial Officer. Estimates of reserves are prepared by technical staff who work directly with the oil and gas properties using industry standard reserve estimation principles, definitions and methodologies. Each year, reserve estimates of the Corporation’s assets are subject to internal technical audits and reviews. In addition, an independent third-party reserve engineer reviews and audits a significant portion of the Corporation’s reported reserves (see pages 93 through 97). Reserve estimates are reviewed by senior management and the Board of Directors.

Qualifications

The person primarily responsible for overseeing the preparation of the Corporation’s oil and gas reserves during 2020 was the Senior Manager, Global Reserves. He is a member of the Society of Petroleum Engineers and has 18 years of experience in the oil and gas industry with a MSc degree in Petroleum Engineering. His experience has been primarily focused on oil and gas subsurface understanding and reserves estimation in both domestic and international areas. He is also responsible for the Corporation’s Global Reserves group, which is the internal organization that establishes the policies and processes used within the operating units to estimate reserves and perform internal technical reserve audits and reviews.

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Reserves Audit

We engaged the consulting firm of DeGolyer and MacNaughton (D&M) to perform an audit of the internally prepared reserve estimates on certain fields aggregating 92% of 2020 year-end reported reserve quantities on a barrel of oil equivalent basis (2019: 80%). The purpose of this audit was to provide additional assurance on the reasonableness of internally prepared reserve estimates and compliance with SEC regulations. The D&M report, dated February 3, 2021, on the Corporation's estimated oil and gas reserves was prepared using standard geological and engineering methods generally recognized in the petroleum industry. D&M is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over 70 years. D&M's letter report on the Corporation's December 31, 2020 oil and gas reserves is included as an exhibit to this Form 10-K. While the D&M report should be read in its entirety, the report concludes that for the properties reviewed by D&M, the total net proved reserve estimates prepared by Hess and audited by D&M, in the aggregate, differed by less than 1% (2019: less than 1%) of total audited net proved reserves on a barrel of oil equivalent basis. The report also includes among other information, the qualifications of the technical person primarily responsible for overseeing the reserve audit.

Crude Oil Prices Used to Estimate Proved Reserves

Proved reserves are calculated using the average price during the twelve-month period before December 31 determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within the year, unless prices are defined by contractual agreements, excluding escalations based on future conditions. Crude oil prices used in the determination of proved reserves at December 31, 2020 were \$39.77 per barrel for WTI (2019: \$55.73; 2018: \$65.55) and \$43.43 per barrel for Brent (2019:

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\$62.54; 2018: \$72.08). New York Mercantile Exchange (NYMEX) natural gas prices used were \$2.16 per mcf in 2020 (2019: \$2.54; 2018: \$3.01).

At December 31, 2020, spot prices for WTI oil closed at \$48.52 per barrel. If crude oil prices in 2021 are at levels below that used in determining 2020 proved reserves, we may recognize negative revisions to our December 31, 2021 proved undeveloped reserves. In addition, we may recognize negative revisions to proved developed reserves, which can vary significantly by asset due to differing operating cost structures. Conversely, price increases in 2021 above those used in determining 2020 proved reserves could result in positive revisions to proved developed and proved undeveloped reserves at December 31, 2021. It is difficult to estimate the magnitude of any potential net negative or positive change in proved reserves at December 31, 2021, due to numerous currently unknown factors, including 2021 crude oil prices, the amount of any additions to proved reserves, positive or negative revisions in proved reserves related to 2021 reservoir performance, the levels to which industry costs will change in response to 2021 crude oil prices, and management's plans as of December 31, 2021 for developing proved undeveloped reserves.

Following are the Corporation's proved reserves:

	Crude Oil & Condensate					Natural Gas Liquids	
	United	Malaysia and				United	
	States	Guyana	JDA	Other (a)	Total	States	Total
	(Millions of bbls)					(Millions of bbls)	
Net Proved Reserves							
At January 1, 2018	433	43	6	177	659	171	171
Revisions of previous estimates	(3)	(3)	1	(12)	(17)	(14)	(14)
Extensions, discoveries and other additions	114	—	2	9	125	39	39
Purchase of minerals in place	3	—	—	—	3	1	1
Sales of minerals in place	(3)	—	—	—	(3)	(8)	(8)
Production	(43)	—	(1)	(9)	(53)	(14)	(14)
At December 31, 2018	501	40	8	165	714	175	175
Revisions of previous estimates	(54)	13	—	(6)	(47)	(29)	(29)
Extensions, discoveries and other additions	112	33	1	11	157	40	40
Production	(51)	—	(2)	(9)	(62)	(17)	(17)
At December 31, 2019	508	86	7	161	762	169	169
Revisions of previous estimates	(94)	78	—	(24)	(40)	(2)	(2)
Extensions, discoveries and other additions	58	48	—	—	106	18	18
Sales of minerals in place	(18)	—	—	—	(18)	(1)	(1)
Production	(53)	(8)	(1)	(3)	(65)	(22)	(22)
At December 31, 2020	401	204	6	134	745	162	162
Net Proved Developed Reserves							
At January 1, 2018	239	—	5	157	401	87	87
At December 31, 2018	266	—	4	149	419	85	85
At December 31, 2019	293	31	5	139	468	90	90

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At December 31, 2020	282	72	4	134	492	120	120
Net Proved Undeveloped Reserves							
At January 1, 2018	194	43	1	20	258	84	84
At December 31, 2018	235	40	4	16	295	90	90
At December 31, 2019	215	55	2	22	294	79	79
At December 31, 2020	119	132	2	—	253	42	42

(a) Other includes our interests in Denmark and Libya.

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	Natural Gas					Total				
	United	Malaysia and				United	Malaysia and			
	States	Guyana	JDA	Other (b)	Total	States	Guyana	JDA	Other (b)	Total
	(Millions of mcf)					(Millions of boe)				
Net Proved Reserves										
At January 1, 2018	880	12	833	216	1,941	751	45	145	213	1,154
Revisions of previous estimates	(24)	—	(21)	(13)	(58)	(21)	(3)	(2)	(15)	(41)
Extensions, discoveries and other additions	177	—	104	11	292	183	—	19	11	213
Purchase of minerals in place	—	—	—	—	—	4	—	—	—	4
Sales of minerals in place	(145)	—	—	—	(145)	(35)	—	—	—	(35)
Production (a)	(75)	—	(132)	(8)	(215)	(70)	—	(23)	(10)	(103)
At December 31, 2018	813	12	784	206	1,815	812	42	139	199	1,192
Revisions of previous estimates	(197)	(7)	31	(11)	(184)	(116)	12	4	(7)	(107)
Extensions, discoveries and other additions	164	2	3	15	184	179	33	2	14	228
Production (a)	(80)	—	(133)	(9)	(222)	(81)	—	(24)	(11)	(116)
At December 31, 2019	700	7	685	201	1,593	794	87	121	195	1,197
Revisions of previous estimates	(17)	68	81	(32)	100	(99)	89	14	(29)	(25)
Extensions, discoveries and other additions	78	9	20	—	107	89	50	3	—	142
Sales of minerals in place	(5)	—	—	—	(5)	(20)	—	—	—	(20)
Production (a)	(103)	(1)	(111)	(4)	(219)	(92)	(8)	(20)	(4)	(124)
At December 31, 2020	653	83	675	165	1,576	672	218	118	162	1,170
Net Proved Developed Reserves										
At January 1, 2018	526	—	696	197	1,419	414	—	121	190	725
At December 31, 2018	432	—	585	192	1,209	423	—	102	181	706
At December 31, 2019	400	3	497	183	1,083	450	31	88	170	739
At December 31, 2020	490	36	543	165	1,234	484	78	94	162	818
Net Proved Undeveloped Reserves										
At January 1, 2018	354	12	137	19	522	337	45	24	23	429
At December 31, 2018	381	12	199	14	606	389	42	37	18	486
At December 31, 2019	300	4	188	18	510	344	56	33	25	458
At December 31, 2020	163	47	132	—	342	188	140	24	—	352

(a) Natural gas production in 2020 includes 16 million mcf used for fuel (2019: 14 million mcf; 2018: 13 million mcf).

(b) Other includes our interests in Denmark and Libya.

Extensions, discoveries and other additions ('Additions')

2020: Total Additions were 142 million boe, of which 12 million boe (8 million barrels of crude oil, 2 million barrels of NGL and 14 million mcf of natural gas) related to proved developed reserves. Additions to proved developed reserves primarily resulted from drilling activity in the Bakken shale play in North Dakota. Additions to proved undeveloped reserves were 130 million boe (98 million barrels of crude oil, 16 million barrels of NGL and 93 million mcf of natural gas) and are discussed in further detail on page 96.

2019: Total Additions were 228 million boe, of which 25 million boe (13 million barrels of crude oil, 6 million barrels of NGL and 35 million mcf of natural gas) related to proved developed reserves. Additions to proved developed reserves primarily resulted from new wells drilled in the Bakken shale play in North Dakota. Additions in the U.S. also included two wells drilled in the Gulf of Mexico. Additions to proved undeveloped reserves were 203 million boe (144 million barrels of crude oil, 34 million barrels of NGL and 149 million mcf of natural gas) and are discussed in further detail on page 97.

2018: Total Additions were 213 million boe, of which 6 million boe (3 million barrels of crude oil and 18 million mcf of natural gas) related to proved developed reserves. Additions to proved developed reserves were primarily from drilling activity in the Bakken shale play in North Dakota. Additions to proved undeveloped reserves were 207 million boe (122 million barrels of crude oil, 39 million barrels of NGL and 274 million mcf of natural gas) and are discussed in further detail on page 97.

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Revisions of previous estimates

2020: Total revisions of previous estimates of proved reserves amounted to a net decrease of 25 million boe, of which revisions of proved developed reserves amounted to an increase of 108 million boe (38 million barrels of crude oil, 30 million barrels of NGL and 237 million mcf of natural gas). In the U.S., revisions to proved developed reserves from the Bakken were a net increase of 55 million boe, comprised of positive revisions of 77 million boe and negative price revisions of 22 million boe. The positive revisions resulted from well performance (50%), updated yield and decline factors (30%) and other changes (20%), primarily driven by cost reductions. In the Gulf of Mexico, net negative revisions were 8 million boe, including 2 million boe of negative price revisions. In Guyana, revisions increased proved developed reserves by 47 million boe related to performance (55%), improved recovery associated with water injection (35%), and increased natural gas for consumption (10%). In Malaysia and JDA, net revisions to proved developed reserves were an increase of 18 million boe due to performance at North Malay Basin and JDA (80%) and the impact of lower crude oil prices on entitlement allocations in the production sharing contract at JDA (20%). Other had negative revisions to proved developed reserves of 4 million boe, primarily in Libya. Revisions associated with proved undeveloped reserves are discussed in further detail on page 97.

2019: Total revisions of previous estimates amounted to a net decrease of 107 million boe, of which revisions of proved developed reserves amounted to a net decrease of 19 million boe (7 million barrels of NGL and 72 million mcf of natural gas). Revisions to proved developed reserves from the Bakken were a net decrease of 25 million boe with approximately 80% relating to changes in expected recoveries of NGL and natural gas and approximately 20% relating to the impact of lower prices. Net revisions from international assets were an increase of 6 million boe. Revisions associated with proved undeveloped reserves are discussed in further detail on page 97.

2018: Total revisions of previous estimates amounted to a net decrease of 41 million boe, of which revisions of proved developed reserves amounted to a net increase of 3 million boe (4 million barrels of crude oil increase, 4 million barrels of NGL decrease and 20 million mcf of natural gas increase). Revisions to proved developed reserves primarily relate to the Bakken. Revisions associated with proved undeveloped reserves are discussed in further detail on page 97.

Sales of minerals in place ('Asset sales')

2020: Asset sales relate to the divestiture of our 28% working interest in the Shenzi Field in the deepwater Gulf of Mexico.

2018: Asset sales primarily include our former interests in the Utica Basin of Ohio.

Proved Undeveloped Reserves

Following are the Corporation's proved undeveloped reserves:

	United States	Guyana	Malaysia and JDA	Other (a)	Total
	(Millions of boe)				
Net Proved Undeveloped Reserves					
At January 1, 2018	337	45	24	23	429
Revisions of previous estimates	(22)	(3)	(6)	(13)	(44)
Extensions, discoveries and other additions	178	—	19	10	207
Transfers to proved developed reserves	(97)	—	—	(2)	(99)
Sales of minerals in place	(7)	—	—	—	(7)
At December 31, 2018	389	42	37	18	486
Revisions of previous estimates	(91)	9	—	(6)	(88)
Extensions, discoveries and other additions	154	34	—	15	203
Transfers to proved developed reserves	(108)	(29)	(4)	(2)	(143)
At December 31, 2019	344	56	33	25	458
Revisions of previous estimates	(146)	42	(4)	(25)	(133)
Extensions, discoveries and other additions	78	50	2	—	130
Transfers to proved developed reserves	(85)	(8)	(7)	—	(100)
Sales of minerals in place	(3)	—	—	—	(3)
At December 31, 2020	188	140	24	—	352

(a) Other includes our interests in Denmark and Libya.

Extensions, discoveries and other additions ('Additions')

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2020: In the United States, additions from the Bakken shale play in North Dakota were 78 million boe, which primarily resulted from new wells planned to be drilled in the next five years, including the impact of optimizing locations in the development plan. In Guyana, additions of 50 million boe were due to the sanction of the Payara project. In Malaysia, additions at the North Malay Basin were due to additional planned wells to be drilled.

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2019: In the United States, additions from the Bakken shale play in North Dakota were 154 million boe, of which approximately 25% of the change results from additional planned wells to be drilled in the next five years, and approximately 75% results from new wells moved into the five-year plan associated with optimization of drilling locations. Additions in Guyana totaling 34 million boe are from the sanction of Phase 2 development at the Liza Field on the Stabroek Block, offshore Guyana. Other additions were at the South Arne Field in Denmark and in Libya due to additional planned wells to be drilled.

2018: In the United States, additions from the Bakken shale play in North Dakota were 168 million boe, of which approximately 40% of the change results from additional planned wells to be drilled in the next five years, approximately 35% results from performance associated with improved well completion designs, and approximately 25% results from other changes, primarily the impact of higher crude oil prices. Additions in the Gulf of Mexico were 10 million boe due to additional planned drilling at the Tubular Bells Field. Additions in Malaysia and JDA include 11 million boe at North Malay Basin and 8 million boe at the JDA relating to additional planned wells to be drilled within the next five years.

Revisions of previous estimates

2020: In the United States, negative reserve revisions of 146 million boe were from the Bakken, which included negative price revisions of 77 million boe, and a decrease of 121 million boe from wells moved outside our management and Board approved five-year plan due to a reduction in planned rig count and optimization of drilling locations in response to the decline in crude oil prices in 2020. These decreases were partially offset by positive revisions of 52 million boe, primarily due to optimized development spacing and increased well productivity. In Guyana, net positive reserve revisions for Liza Phase 1 and Phase 2 totaling 42 million boe resulted from improved recovery associated with water injection (45%), the impact of lower crude oil prices on entitlement allocations in the production sharing contract (40%) and increased natural gas for consumption (15%). For Other, net negative reserves revisions were 14 million boe in Libya and 11 million boe in Denmark due to moving planned wells outside our five-year plan in response to the decline in crude oil prices in 2020.

2019: Negative reserve revisions in the United States of 91 million boe were largely from the Bakken (94 million boe), of which approximately 75% resulted from wells moved outside our five-year plan associated with optimization of drilling locations. The remaining 25% of negative revisions in the Bakken were caused by lower commodity prices. The net positive reserve revisions in Guyana of 9 million boe relate to the Liza Phase 1 development due to the impact of lower crude oil prices on entitlement allocations in the production sharing agreement.

2018: Negative reserve revisions in the United States totaling 22 million boe, primarily resulted from optimizing drilling plans at the Bakken. Negative reserve revisions in international assets primarily resulted from updates in drilling plans in Denmark and North Malay Basin, and the impact of crude oil price changes on our production sharing agreement in Guyana.

Transfers to proved developed reserves ('Transfers')

2020: Transfers from proved undeveloped reserves resulting from drilling activity included 83 million boe in the Bakken, 2 million boe in the Gulf of Mexico, 8 million boe for Liza Phase 1 in Guyana, and 7 million boe in the North Malay Basin.

2019: Transfers from proved undeveloped reserves included 100 million boe in the Bakken associated with drilling activity, 29 million boe at the Stabroek Block in Guyana where first production was achieved in 2019, and 8 million boe at the Tubular Bells Field in the Gulf of Mexico associated with drilling activity.

2018: Transfers from proved undeveloped reserves included 75 million boe in the Bakken associated with drilling activity, and 22 million boe at the Stampede Field in the Gulf of Mexico where first production was achieved in 2018.

In 2020, capital expenditures of \$1,090 million were incurred to convert proved undeveloped reserves to proved developed reserves (2019: \$1,750 million; 2018: \$1,070 million).

At December 31, 2020, projects that have proved reserves that have been classified as undeveloped for a period in excess of five years totaled 4.7 million boe, or less than 1% of total proved reserves, primarily related to the multi-phase development at North Malay Basin, offshore Malaysia.

Production Sharing Contracts

The Corporation's proved reserves include crude oil and natural gas reserves relating to long-term agreements with governments or authorities in which the Corporation has the legal right to produce or has a revenue interest in the production. The Corporation's operations with these production sharing arrangements include those in Guyana, Malaysia, and the JDA. Proved reserves for each of the three years ended December 31, 2020, as well as volumes produced and received during 2020, 2019 and 2018 from these production sharing contracts are presented in the proved

reserve tables on pages 94 and 95. Revisions resulting from the entitlement impact of price changes in production sharing contracts increased proved reserves by 22 million boe in 2020 (2019: 5 million boe increase; 2018: 7 million boe decrease).

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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

Future net cash flows are calculated by applying prescribed oil and gas selling prices used in determining year-end reserve estimates (adjusted for price changes provided by contractual arrangements) to estimated future production of proved oil and gas reserves, less estimated future development and production costs, which are based on year-end costs and existing economic assumptions. Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the pre-tax net cash flows, as well as including the effect of tax deductions and tax credits and allowances relating to the Corporation's proved oil and gas reserves. Future net cash flows are discounted at the prescribed rate of 10%.

The prices used for the discounted future net cash flows in 2020 were \$39.77 per barrel for WTI (2019: \$55.73; 2018: \$65.55) and \$43.43 per barrel for Brent (2019: \$62.54; 2018: \$72.08) and do not include the effects of commodity hedges. NYMEX natural gas prices used were \$2.16 per mcf in 2020 (2019: \$2.54; 2018: \$3.01). Selling prices have in the past, and can in the future, fluctuate significantly. As a result, selling prices used in the disclosure of future net cash flows may not be representative of future selling prices. In addition, the discounted future net cash flow estimates do not include exploration expenses, interest expense or corporate general and administrative expenses. The amount of tax deductions, credits, and allowances relating to the Corporation's proved oil and gas reserves can change year to year due to factors including changes in proved reserves, variances in actual pre-tax cash flows from forecasted pre-tax cash flows in historical periods, and the impact to year-end carryforward tax attributes associated with deducting in the Corporation's income tax returns exploration expenses, interest expense, and corporate general and administrative expenses that are not contemplated in the standardized measure computations. The future net cash flow estimates could be materially different if other assumptions were used.

At December 31	United			Malaysia and	
	Total	States	Guyana	JDA	Other (a)
	(In millions)				
2020					
Future revenues	\$ 28,745	\$ 11,757	\$ 8,362	\$ 2,578	\$ 6,048
Less:					
Future production costs	12,360	6,887	2,784	1,073	1,616
Future development costs	6,322	2,593	2,617	677	435
Future income tax expenses	4,135	45	380	110	3,600
	<u>22,817</u>	<u>9,525</u>	<u>5,781</u>	<u>1,860</u>	<u>5,651</u>
Future net cash flows	5,928	2,232	2,581	718	397
Less: Discount at 10% annual rate	2,343	1,205	935	123	80
Standardized Measure of Discounted Future Net Cash Flows	<u>\$ 3,585</u>	<u>\$ 1,027</u>	<u>\$ 1,646</u>	<u>\$ 595</u>	<u>\$ 317</u>
2019					
Future revenues	\$ 44,778	\$ 25,223	\$ 5,326	\$ 3,473	\$ 10,756
Less:					
Future production costs	14,176	10,189	931	1,238	1,818
Future development costs	8,267	5,104	1,549	823	791
Future income tax expenses	8,560	1,291	505	162	6,602
	<u>31,003</u>	<u>16,584</u>	<u>2,985</u>	<u>2,223</u>	<u>9,211</u>
Future net cash flows	13,775	8,639	2,341	1,250	1,545
Less: Discount at 10% annual rate	5,390	3,872	539	270	709
Standardized Measure of Discounted Future Net Cash Flows	<u>\$ 8,385</u>	<u>\$ 4,767</u>	<u>\$ 1,802</u>	<u>\$ 980</u>	<u>\$ 836</u>
2018					
Future revenues	\$ 50,948	\$ 31,460	\$ 2,826	\$ 4,443	\$ 12,219
Less:					
Future production costs	13,636	9,718	605	1,324	1,989
Future development costs	8,427	6,132	596	949	750
Future income tax expenses	10,950	2,641	334	233	7,742
	<u>33,013</u>	<u>18,491</u>	<u>1,535</u>	<u>2,506</u>	<u>10,481</u>
Future net cash flows	17,935	12,969	1,291	1,937	1,738
Less: Discount at 10% annual rate	7,285	5,437	553	492	803
Standardized Measure of Discounted Future Net Cash Flows	<u>\$ 10,650</u>	<u>\$ 7,532</u>	<u>\$ 738</u>	<u>\$ 1,445</u>	<u>\$ 935</u>

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(a) Other includes our interests in Denmark and Libya.

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Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

For the Years Ended December 31	2020	2019	2018
	(In millions)		
Standardized Measure of Discounted Future Net Cash Flows at January 1	\$ 8,385	\$ 10,650	\$ 6,356
Changes during the year:			
Sales and transfers of oil and gas produced during the year, net of production costs	(1,829)	(2,842)	(2,755)
Development costs incurred during the year	1,479	2,262	1,533
Net changes in prices and production costs	(10,141)	(5,761)	7,076
Net change in estimated future development costs	1,860	(186)	(1,119)
Extensions and discoveries (including improved recovery) of oil and gas reserves, less related costs	543	1,591	2,129
Revisions of previous oil and gas reserve estimates	364	(281)	(630)
Net purchases (sales) of minerals in place, before income taxes	(500)	—	(83)
Accretion of discount	1,220	1,635	929
Net change in income taxes	2,091	1,305	(2,662)
Revision in rate or timing of future production and other changes	113	12	(124)
Total	(4,800)	(2,265)	4,294
Standardized Measure of Discounted Future Net Cash Flows at December 31	\$ 3,585	\$ 8,385	\$ 10,650

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Based upon their evaluation of the Corporation's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15 (e)) as of December 31, 2020, John B. Hess, Chief Executive Officer, and John P. Rielly, Chief Financial Officer, concluded that these disclosure controls and procedures were effective as of December 31, 2020.

There was no change in internal controls over financial reporting identified in the evaluation required by paragraph (d) of Rules 13a-15 or 15d-15 in the quarter ended December 31, 2020 that has materially affected, or is reasonably likely to materially affect, internal controls over financial reporting.

Management's report on internal control over financial reporting and the attestation report on the Corporation's internal controls over financial reporting are included in *Item 8. Financial Statements and Supplementary Data* of this annual report on Form 10-K.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

For information regarding our executive officers, see Part I of this Annual Report on Form 10-K. Additional information required by this item is incorporated herein by reference to the Corporation's definitive proxy statement for the 2021 annual meeting of stockholders.

The Corporation has adopted a Code of Business Conduct and Ethics applicable to the Corporation's directors, officers (including the Corporation's principal executive officer and principal financial officer) and employees. The Code of Business Conduct and Ethics is available on the Corporation's website. In the event that we amend or waive any of the provisions of the Code of Business Conduct and Ethics that relate to any element of the code of ethics definition enumerated in Item 406(b) of Regulation S-K, we intend to disclose the same on the Corporation's

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website at www.hess.com.

Item 11. Executive Compensation

Information relating to executive compensation is incorporated herein by reference to the Corporation's definitive proxy statement for the 2021 annual meeting of stockholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information pertaining to security ownership of certain beneficial owners and management is incorporated herein by reference to the Corporation's definitive proxy statement for the 2021 annual meeting of stockholders.

See Equity Compensation Plans in *Item 5. Market for the Registrant's Common Stock, Related Stockholder Matters and Issuer Purchases of Equity Securities* for information pertaining to securities authorized for issuance under equity compensation plans.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information relating to this item is incorporated herein by reference to the Corporation's definitive proxy statement for the 2021 annual meeting of stockholders.

Item 14. Principal Accounting Fees and Services

Information relating to this item is incorporated herein by reference to the Corporation's definitive proxy statement for the 2021 annual meeting of stockholders.

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PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are made a part of this Annual Report on Form 10-K:

1. and 2. Financial statements and financial statement schedules

The financial statements filed as part of this Annual Report on Form 10-K are listed in the accompanying index to financial statements and schedules in *Item 8. Financial Statements and Supplementary Data*.

All other financial statement schedules required under SEC rules that are not included in this Annual Report on Form 10-K, are omitted either because they are not applicable or the required information is contained in *Item 8. Financial Statements and Supplementary Data*.

3. Exhibits

The exhibits required to be filed pursuant to Item 15(b) of Form 10-K are listed in the Exhibit Index filed herewith, which Exhibit Index is incorporated herein by reference.

- 3(1) [Restated Certificate of Incorporation of Registrant, including amendment thereto dated May 3, 2006 incorporated by reference to Exhibit 3\(1\) of Registrant's Form 10-Q for the three months ended June 30, 2006.](#)
- 3(2) [Certificate of Amendment to Restated Certificate of Incorporation of Registrant, dated May 22, 2013, incorporated by reference to Exhibit 3\(1\) of Form 8-K of Registrant filed on May 22, 2013.](#)
- 3(3) [Certificate of Amendment to Restated Certificate of Incorporation of Registrant, effective May 12, 2014, incorporated by reference to Exhibit 3\(1\) of Form 8-K of Registrant filed on May 13, 2014.](#)
- 3(4) [Certificate of Elimination of 8.00% Series A Mandatory Convertible Preferred Stock of Registrant, incorporated by reference to Exhibit 3\(4\) of Form 10-K of Registrant for the year ended December 31, 2019.](#)
- 3(5) [By-Laws of Hess Corporation \(as amended effective May 6, 2020\) incorporated by reference to Exhibit 3\(1\) of Form 10-Q of Registrant for the three months ended March 31, 2020.](#)
- 4(1) [Credit Agreement, dated as of April 18, 2019, among Hess Corporation, the subsidiary party thereto, the lenders party thereto, and JPMorgan Chase Bank, N.A., as administrative agent incorporated by reference to Exhibit 10\(1\) of Form 8-K of the Registrant, filed on April 23, 2019.](#)
- 4(2) [Indenture dated as of October 1, 1999, between Registrant and The Chase Manhattan Bank, as Trustee, incorporated by reference to Exhibit 4\(1\) of Form 10-Q of Registrant for the three months ended September 30, 1999.](#)
- 4(3) [First Supplemental Indenture, dated as of October 1, 1999, between Registrant and The Chase Manhattan Bank, as Trustee, relating to Registrant's 73/8% Notes due 2009 and 77/8% Notes due 2029, incorporated by reference to Exhibit 4\(2\) of Form 10-Q of Registrant for the three months ended September 30, 1999.](#)
- 4(4) [Prospectus Supplement, dated August 8, 2001, to Prospectus dated July 27, 2001 relating to Registrant's 5.30% Notes due 2004, 5.90% Notes due 2006, 6.65% Notes due 2011 and 7.30% Notes due 2031, incorporated by reference to Registrant's](#)

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[prospectus filed pursuant to Rule 424\(b\)\(2\) under the Securities Act of 1933, as amended, on August 9, 2001.](#)

- [4\(5\) Prospectus Supplement, dated February 28, 2002, to Prospectus dated July 27, 2001 relating to Registrant's 7.125% Notes due 2033, incorporated by reference to Registrant's prospectus filed pursuant to Rule 424\(b\)\(4\) under the Securities Act of 1933, as amended, on March 1, 2002.](#)
- [4\(6\) Indenture dated as of March 1, 2006, between Registrant and The Bank of New York Mellon, as successor to JP Morgan Chase Bank, N.A., as Trustee, including form of Note, incorporated by reference to Exhibit 4 to Registrant's Form S-3ASR filed on March 1, 2006.](#)
- [4\(7\) Form of 6.00% Note due 2040, incorporated by reference to Exhibit 4\(1\) to Form 8-K of Registrant filed on December 15, 2009.](#)
- [4\(8\) Form of 5.60% Note due 2041, incorporated by reference to Exhibit 4\(1\) to Form 8-K of Registrant filed on August 12, 2010.](#)
- [4\(9\) Form of 3.50% Note due 2024, incorporated by reference to Exhibit 4\(3\) to Form 8-K of Registrant filed on June 25, 2014.](#)
- [4\(10\) Form of 4.30% Note due 2027, incorporated by reference to Exhibit 4\(1\) to Form 8-K of Registrant filed on September 28, 2016.](#)
- [4\(11\) Form of 5.80% Note due 2047, incorporated by reference to Exhibit 4\(2\) to Form 8-K of Registrant filed on September 28, 2016.](#)
- [4\(12\) Description of Hess Corporation's Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 incorporated by reference to Exhibit 4\(12\) of Form 10-K of Registrant for the year ended December 31, 2019.](#)

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- [4\(13\) Loan Agreement, dated as of March 16, 2020, among Hess Corporation, the lenders party thereto, and JPMorgan Chase Bank, N.A., as administrative agent incorporated by reference to Exhibit 10\(1\) of Form 8-K of the Registrant, filed on March 17, 2020.](#)
- [4\(14\) Amendment No. 1 dated as of June 9, 2020 to the Term Loan Agreement dated as of March 16, 2020, among Hess Corporation, the lenders party thereto, and JPMorgan Chase Bank, N.A., as administrative agent incorporated by reference to Exhibit 10\(1\) of Form 10-Q of Registrant for the three months ended June 30, 2020.](#)
Other instruments defining the rights of holders of long-term debt of Registrant and its consolidated subsidiaries are not being filed since the total amount of securities authorized under each such instrument does not exceed 10% of the total assets of Registrant and its subsidiaries on a consolidated basis. Registrant agrees to furnish to the Securities and Exchange Commission a copy of any instruments defining the rights of holders of long-term debt of Registrant and its subsidiaries upon request.
- [10\(1\)* Annual Cash Incentive Plan description incorporated by reference to Item 5.02 of Form 8-K of Registrant filed on March 6, 2020.](#)
- [10\(2\)* Annual Cash Incentive Plan description incorporated by reference to Item 5.02 of Form 8-K of Registrant filed on June 5, 2020.](#)
- [10\(3\)* Financial Counseling Program description incorporated by reference to Exhibit 10\(6\) of Form 10-K of Registrant for the fiscal year ended December 31, 2004.](#)
- [10\(4\)* Hess Corporation Savings and Stock Bonus Plan incorporated by reference to Exhibit 10\(7\) of Form 10-K of Registrant for the fiscal year ended December 31, 2006.](#)
- [10\(5\)* Hess Corporation Pension Restoration Plan, dated January 19, 1990, incorporated by reference to Exhibit 10\(9\) of Form 10-K of Registrant for the fiscal year ended December 31, 1989. \(P\)](#)
- [10\(6\)* Amendment, dated December 31, 2006, to Hess Corporation Pension Restoration Plan, incorporated by reference to Exhibit 10\(10\) of Form 10-K of Registrant for the fiscal year ended December 31, 2006.](#)
- [10\(7\)* Letter Agreement, dated May 17, 2001, between Registrant and John P. Rielly relating to Mr. Rielly's participation in the Hess Corporation Pension Restoration Plan, incorporated by reference to Exhibit 10\(18\) of Form 10-K of Registrant for the fiscal year ended December 31, 2002.](#)
- [10\(8\)* Amended and Restated 2008 Long-term Incentive Plan, incorporated by reference to exhibit 10\(1\) of Form 8-K of the Registrant filed on May 12, 2015.](#)
- [10\(9\)* Forms of Awards under Registrant's 2008 Long-term Incentive Plan, incorporated by reference to Exhibit 10\(14\) of Form 10-K of Registrant for the fiscal year ended December 31, 2009.](#)
- [10\(10\)* Form of Restricted Stock Award Agreement under Registrant's Amended and Restated 2008 Long-term Incentive Plan, incorporated by reference to Exhibit 10\(2\) of Form 10-Q of Registrant for the three months ended March 31, 2015.](#)
- [10\(11\)* Compensation program description for non-employee directors, incorporated by reference to Item 1.01 of Form 8-K of Registrant filed on January 4, 2007.](#)
- [10\(12\)* Form of Amended and Restated Change in Control Termination Benefits Agreement, dated as of May 29, 2009, incorporated by reference to Exhibit 10\(1\) of Form 10-Q of Registrant for the three months ended June 30, 2009. A substantially identical agreement \(differing only in the signatories thereto\) was entered into between Registrant and John B. Hess.](#)
- [10\(13\)* Amended and Restated Change in Control Termination Benefits Agreement, dated as of May 29, 2009, between Registrant and John P. Rielly, incorporated by reference to Exhibit 10\(17\) of Form 10-K of Registrant for the fiscal year ended December 31, 2009. Substantially identical agreements \(differing only in the signatories thereto\) were entered into between Registrant and other executive officers \(including the named executive officers, other than Michael Turner and John B. Hess\).](#)
- [10\(14\)* Form of Change in Control Termination Benefits Agreement, dated as of August 3, 2015, between the Registrant and Michael R. Turner, incorporated by reference to Exhibit 10\(3\) of Form 10-Q of Registrant for the three months ended June 30, 2015. Substantially identical agreements \(differing only in the signatories thereto\) were entered into between the Registrant](#)

and four other senior officers.

- [10\(15\)* Agreement between Registrant and Gregory P. Hill, relating to Mr. Hill's compensation and other terms of employment, incorporated by reference to Item 5.02 of Form 8-K of Registrant filed January 7, 2009.](#)
- [10\(16\)* Agreement between Registrant and Timothy B. Goodell, relating to Mr. Goodell's compensation and other terms of employment, incorporated by reference to Exhibit 10\(20\) of Registrant's Form 10-K for the fiscal year ended December 31, 2009.](#)
- [10\(17\)* Deferred Compensation Plan of Registrant, dated December 1, 1999, incorporated by reference to Exhibit 10\(16\) of Form 10-K of Registrant for the fiscal year ended December 31, 1999.](#)
- [10\(18\)* Hess Corporation 2017 Long-Term Incentive Plan, incorporated by reference to Exhibit 10\(1\) of Form 8-K of Registrant filed on June 13, 2017.](#)
- [10\(19\)* Form of Restricted Stock Award Agreement under the 2017 Long-Term Incentive Plan incorporated by reference to Exhibit 10\(1\) of Form 10-Q of Registrant for the three months ended March 31, 2020. Substantially identical agreements were entered into by the Registrant during 2018 and 2019.](#)

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- [10\(20\)* Form of Stock Option Award Agreement under the 2017 Long-Term Incentive Plan incorporated by reference to Exhibit 10\(2\) of Form 10-Q of Registrant for the three months ended March 31, 2020. Substantially identical agreements were entered into by the Registrant during 2018 and 2019.](#)
- [10\(21\)* Form of Performance Award Agreement under the 2017 Long-Term Incentive Plan, incorporated by reference to Exhibit 10\(3\) of Form 10-Q of Registrant for the three months ended March 31, 2019. Substantially identical agreements were entered into by the Registrant during 2018.](#)
- [10\(22\)* Form of 2020 Performance Award Agreement under the 2017 Long-Term Incentive Plan incorporated by reference to Exhibit 10\(3\) of Form 10-Q of Registrant for the three months ended March 31, 2020.](#)
- [10\(23\)* Separation Agreement, dated November 6, 2019, between Registrant and Michael R. Turner incorporated by reference to Exhibit 10\(21\) of Form 10-K of Registrant for the year ended December 31, 2019.](#)
- [21 Subsidiaries of Registrant.](#)
- [24 Power of Attorney \(included on the signatures page of this Annual Report on Form 10-K\).](#)
- [23\(1\) Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm, dated March 1, 2021.](#)
- [23\(2\) Consent of DeGolyer and MacNaughton dated March 1, 2021.](#)
- [31\(1\) Certification required by Rule 13a-14\(a\) \(17 CFR 240.13a-14\(a\)\) or Rule 15d-14\(a\) \(17 CFR 240.15d-14\(a\)\).](#)
- [31\(2\) Certification required by Rule 13a-14\(a\) \(17 CFR 240.13a-14\(a\)\) or Rule 15d-14\(a\) \(17 CFR 240.15d-14\(a\)\).](#)
- [32\(1\) Certification required by Rule 13a-14\(b\) \(17 CFR 240.13a-14\(b\)\) or Rule 15d-14\(b\) \(17 CFR 240.15d-14\(b\)\) and Section 1350 of Chapter 63 of Title 18 of the United States Code \(18 U.S.C. 1350\).](#)
- [32\(2\) Certification required by Rule 13a-14\(b\) \(17 CFR 240.13a-14\(b\)\) or Rule 15d-14\(b\) \(17 CFR 240.15d-14\(b\)\) and Section 1350 of Chapter 63 of Title 18 of the United States Code \(18 U.S.C. 1350\).](#)
- [99\(1\) Letter report of DeGolyer and MacNaughton, Independent Petroleum Engineering Consulting Firm, dated February 3, 2021, on proved reserves audit as of December 31, 2020 of certain properties attributable to Registrant.](#)

101(INS) Inline XBRL Instance Document

101(SCH) Inline XBRL Schema Document

101(CAL) Inline XBRL Calculation Linkbase Document

101(LAB) Inline XBRL Labels Linkbase Document

101(PRE) Inline XBRL Presentation Linkbase Document

101(DEF) Inline XBRL Definition Linkbase Document

104 The cover page from the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2020 has been formatted in Inline XBRL.

* These exhibits relate to executive compensation plans and arrangements.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 1st day of March 2021.

HESS CORPORATION
(Registrant)

By /s/ JOHN P. RIELLY

(John P. Rielly)

Executive Vice President and

Chief Financial Officer

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POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints John B. Hess, Timothy B. Goodell and John P. Rielly or any of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and to perform each and every act and thing requisite and necessary to be done in and about the premises, as fully and to all intents and purposes as he or she might or would do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his or her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ John B. Hess</u> John B. Hess	Director and Chief Executive Officer (Principal Executive Officer)	March 1, 2021
<u>/s/ James H. Quigley</u> James H. Quigley	Director and Chairman of the Board	March 1, 2021
<u>/s/ Terrence J. Checki</u> Terrence J. Checki	Director	March 1, 2021
<u>/s/ Leonard S. Coleman Jr.</u> Leonard S. Coleman Jr.	Director	March 1, 2021
<u>/s/ Joaquín Duato</u> Joaquín Duato	Director	March 1, 2021
<u>/s/ Edith E. Holiday</u> Edith E. Holiday	Director	March 1, 2021
<u>/s/ Marc S. Lipschultz</u> Marc S. Lipschultz	Director	March 1, 2021
<u>/s/ David McManus</u> David McManus	Director	March 1, 2021
<u>/s/ Dr. Kevin O. Meyers</u> Dr. Kevin O. Meyers	Director	March 1, 2021

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/s/ Karyn F. Ovelmen

Karyn F. Ovelmen

Director

March 1, 2021

Executive Vice President and Chief

/s/ John P. Rielly

John P. Rielly

Financial Officer

March 1, 2021

(Principal Financial and Accounting
Officer)

/s/ William G. Schrader

William G. Schrader

Director

March 1, 2021

Exhibit 21

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUBSIDIARIES OF THE REGISTRANT

Name of Company	Registrant ownership %	Jurisdiction
Hess Asia Holdings Inc.	100%	Cayman Islands
Hess Bakken Investments II, LLC	100%	Delaware
Hess Bakken Investments III, LLC	100%	Delaware
Hess Bakken Investments IV, LLC	100%	Delaware
Hess Bakken Processing LLC	47%	Delaware
Hess Baldpate-Penn State LLC	100%	Delaware
Hess Canada (Aspy) Exploration Limited	100%	Cayman Islands
Hess Canada Exploration Limited	100%	Cayman Islands
Hess Canada Oil and Gas ULC	100%	Nova Scotia, Canada
Hess Capital Limited	100%	Cayman Islands
Hess Capital Services Holdings, LLC	100%	Delaware
Hess Capital Services LLC	100%	Delaware
Hess Conger LLC	100%	Delaware
Hess Denmark ApS	100%	Denmark
Hess Energy Exploration LLC	100%	Delaware
Hess Equatorial Guinea Investments Limited	100%	Cayman Islands
Hess Exploration & Production Holdings Limited	100%	Delaware
Hess Exploration and Production Malaysia B.V.	100%	The Netherlands
Hess Exploration Services, Inc.	100%	Delaware
Hess Finance	100%	England & Wales
Hess GOM Deepwater LLC	100%	Delaware
Hess GOM Deepwater Sub-Holdings LLC	100%	Delaware
Hess GOM Exploration LLC	100%	Delaware
Hess Guyana (Block B) Exploration Limited	100%	Cayman Islands
Hess Guyana (Liza) Exploration Limited	100%	Cayman Islands
Hess Guyana Exploration Limited	100%	Cayman Islands
Hess Holdings EG Limited	100%	Cayman Islands
Hess Holdings GOM Ventures LLC	100%	Delaware
Hess Holdings West Africa Limited	100%	Cayman Islands
Hess (Indonesia-VIII) Holdings Limited	100%	Cayman Islands
Hess Infrastructure Partners LP	47%	Delaware
Hess International Holdings Corporation	100%	Delaware
Hess International Holdings Limited	100%	Cayman Islands
Hess International Receivables Limited	100%	Cayman Islands
Hess International Sales LLC	100%	Delaware
Hess Libya (Waha) Limited	100%	Cayman Islands
Hess Libya Exploration Limited	100%	Cayman Islands
Hess Limited	100%	England & Wales
Hess Llano LLC	100%	Delaware
Hess Middle East New Ventures Limited	100%	Cayman Islands

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Name of Company	Registrant ownership %	Jurisdiction
Hess Midstream Operations LP	47%	Delaware
Hess Midstream Partners GP LP	47%	Delaware
Hess (Netherlands) Oil and Gas Holdings C.V.	100%	The Netherlands

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Hess New Ventures Exploration Limited	100%	Cayman Islands
Hess North Dakota Export Logistics Holdings LLC	47%	Delaware
Hess North Dakota Export Logistics LLC	47%	Delaware
Hess North Dakota Export Logistics Operations LP	47%	Delaware
Hess North Dakota Pipelines Holdings LLC	47%	Delaware
Hess North Dakota Pipelines LLC	47%	Delaware
Hess NWE Holdings	100%	England & Wales
Hess Offshore Response Company, LLC	100%	Delaware
Hess Ohio Developments, LLC	100%	Delaware
Hess Ohio Holdings, LLC	100%	Delaware
Hess Ohio Sub-Holdings LLC	100%	Delaware
Hess Oil & Gas Sdn. Bhd.	100%	Malaysia
Hess Oil and Gas Holdings Inc.	100%	Cayman Islands
Hess Oil Company of Thailand (JDA) Limited	100%	Cayman Islands
Hess Oil Company of Thailand Ltd. Co.	100%	Texas
Hess Services UK Limited	100%	England & Wales
Hess Stampede LLC	100%	Delaware
Hess Suriname Exploration Limited	100%	Cayman Islands
Hess Tank Cars Holdings II LLC	47%	Delaware
Hess Tank Cars II LLC	47%	Delaware
Hess Tank Cars LLC	47%	Delaware
Hess TGP Finance Company LLC	100%	Delaware
Hess TGP Holdings LLC	47%	Delaware
Hess TGP Operations LP	47%	Delaware
Hess Tioga Gas Plant LLC	47%	Delaware
Hess Trading Corporation	100%	Delaware
Hess Tubular Bells LLC	100%	Delaware
Hess Water Services LLC	47%	Delaware
Hess West Africa Holdings Limited	100%	Cayman Islands

Exhibit 23(1)

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

- a. Registration Statement (Form S-8 No. 333-43569) pertaining to the Hess Corporation Employees' Savings Plan,
- b. Registration Statement (Form S-8 No. 333-150992) pertaining to the Hess Corporation Amended and Restated 2008 Long-Term Incentive Plan and the Hess Corporation 2017 Long-Term Incentive Plan,
- c. Registration Statement (Form S-8 No. 333-167076) pertaining to the Hess Corporation Amended and Restated 2008 Long-Term Incentive Plan and the Hess Corporation 2017 Long-Term Incentive Plan,
- d. Registration Statement (Form S-8 No. 333-181704) pertaining to the Hess Corporation Amended and Restated 2008 Long-Term Incentive Plan and the Hess Corporation 2017 Long-Term Incentive Plan,
- e. Registration Statement (Form S-8 No. 333-204929) pertaining to the Hess Corporation Amended and Restated 2008 Long-Term Incentive Plan and the Hess Corporation 2017 Long-Term Incentive Plan,
- f. Registration Statement (Form S-8 No. 333-219113) pertaining to the Hess Corporation 2017 Long-Term Incentive Plan, and
- g. Registration Statement (Form S-3 No. 333-223279) of Hess Corporation;

of our reports dated March 1, 2021, with respect to the consolidated financial statements of Hess Corporation and the effectiveness of internal control over financial reporting of Hess Corporation included in this Annual Report (Form 10-K) of Hess Corporation for the year ended December 31, 2020.

/s/ Ernst & Young LLP

New York, New York
March 1, 2021

FWE-0040172

Exhibit 23(2)

DeGolyer and MacNaughton

5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

March 1, 2021

Hess Corporation
1185 Avenue of the Americas
New York, New York 10036

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton as an independent petroleum engineering consulting firm, to references to our report of third party dated February 3, 2021, containing our opinion on the estimated proved reserves, as of December 31, 2020, attributable to certain properties in which Hess Corporation has represented it holds an interest (our "Report") under the heading "Proved Oil and Gas Reserves-Reserves Audit," and to the inclusion of our Report as an exhibit in Hess Corporation's Annual Report on Form 10-K for the year ended December 31, 2020. We also consent to all such references, including under the heading "Experts," and to the incorporation by reference of our Report in the Registration Statements filed by Hess Corporation on Form S-3 (No. 333-223279) and Form S-8 (No. 333-43569, No. 333-150992, No. 333-167076, No. 333-181704, No. 333-204929, and No. 333-219113).

Very truly yours,

/s/DeGolyer and MacNaughton
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

FWE-0040173

Exhibit 31(1)

I, John B. Hess, certify that:

1. I have reviewed this annual report on Form 10-K of Hess Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

By /s/ John B. Hess
John B. Hess
Chief Executive Officer

Date: March 1, 2021

Exhibit 31(2)

I, John P. Rielly, certify that:

1. I have reviewed this annual report on Form 10-K of Hess Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

By /s/ John P. Rielly

John P. Rielly
Executive Vice President and
Chief Financial Officer

Date: March 1, 2021

FWE-0040175

Exhibit 32(1)

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Hess Corporation (the Corporation) on Form 10-K for the period ended December 31, 2020 as filed with the Securities and Exchange Commission on the date hereof (the Report), I, John B. Hess, Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

- (1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

By /s/ John B. Hess

John B. Hess
Chief Executive Officer

Date: March 1, 2021

A signed original of this written statement required by Section 906 has been provided to the Corporation and will be retained by the Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

FWE-0040176

Exhibit 32(2)

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Hess Corporation (the Corporation) on Form 10-K for the period ended December 31, 2020 as filed with the Securities and Exchange Commission on the date hereof (the Report), I, John P. Rielly, Executive Vice President and Chief Financial Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

- (1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

By /s/ John P. Rielly
John P. Rielly
Executive Vice President and
Chief Financial Officer

Date: March 1, 2021

A signed original of this written statement required by Section 906 has been provided to the Corporation and will be retained by the Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

FWE-0040177

DeGolyer and MacNaughton

Exhibit 99.1

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 3, 2021

Board of Directors
Hess Corporation
1185 Avenue of the Americas
New York, New York 10036

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2020, of the net proved oil, condensate, natural gas liquids (NGL), and gas reserves of certain properties in which Hess Corporation (Hess) has represented it holds an interest to determine the reasonableness of Hess' estimates. This evaluation was completed on February 3, 2021. Hess has represented to us that these properties account for approximately 92.0 percent on a net equivalent barrel basis of Hess' net proved reserves, as of December 31, 2020, and that the net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4-10(a) (1)–(32) of Regulation S–X of the Securities and Exchange Commission (SEC) of the United States. It is our opinion that the procedures and methodologies employed by Hess for the preparation of its proved reserves estimates as of December 31, 2020, comply with the current requirements of the SEC. We have reviewed information provided to us by Hess that it represents to be Hess' estimates of the net reserves, as of December 31, 2020, for the same properties as those which we evaluated. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Hess.

Reserves estimates included herein are expressed as net reserves as represented by Hess. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2020. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Hess after deducting all interests held by others.

Certain properties in which Hess has represented that it holds an interest are subject to the terms of production sharing contracts (PSC). The terms of these PSCs generally allow for working interest participants to be reimbursed for portions of capital costs and operating expenses and to share in the profits. The reimbursements and profit proceeds are converted to a barrel of oil equivalent or standard cubic foot of gas equivalent by dividing by product prices to estimate the "entitlement quantities." These entitlement quantities are equivalent in principle to net reserves and are used to calculate an equivalent net share, termed an "entitlement interest." In this report, Hess' net reserves or interest for the properties subject to these PSCs is the entitlement based on Hess' working interest.

Estimates of reserves should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Information used in the preparation of this report was obtained from Hess. In the preparation of this report we have relied, without independent verification, upon such information furnished by Hess with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination was not considered necessary for the purposes of this report.

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FWE-0040178

Definition of Reserves

Petroleum reserves estimated by Hess included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used by Hess in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved oil and gas reserves – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes: (A) The area identified by drilling and limited by fluid contacts, if any; and, (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and, (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic and operating conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [Section 210.4–10(a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019” and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Hess, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved.

The proved undeveloped reserves estimates were based on opportunities identified in the plan of development provided by Hess.

Hess has represented that its senior management is committed to the development plan provided by Hess and that Hess has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include quality control, identification of flow regimes, and characteristic well performance behavior. These analyses were performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and original gas in place (OGIP). Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data were available and when circumstances justified, material-balance methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP and OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors based on an analysis of reservoir performance, including production rate, reservoir pressure, and reservoir fluid properties.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production as defined under the Definition of Reserves heading of this report or the expiration of the fiscal agreement, as appropriate.

In certain cases, reserves were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

DeGolyer and MacNaughton

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Data provided by Hess from wells drilled through December 31, 2020, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available only through August 2020. Estimated cumulative production, as of December 31, 2020, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 4 months.

Oil and condensate reserves estimated herein are to be recovered by normal field separation. NGL reserves estimated herein include pentanes and heavier fractions (C5+) and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions, and are the

result of low-temperature plant processing. Oil, condensate, and NGL reserves included in this report are expressed in millions of barrels (10⁶bbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as fuel gas and marketable gas. Marketable gas is defined as the total gas produced from the reservoir after reduction for shrinkage resulting from field separation; processing, including removal of the nonhydrocarbon gas to meet pipeline specifications; and flare and other losses but not from fuel usage. Fuel gas is that portion of the gas consumed in field operations. Gas reserves estimated herein are reported as marketable gas; therefore, fuel gas is included as reserves. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.7 pounds per square inch absolute (psia). Gas quantities included in this report are expressed in billions of cubic feet (10⁹ft³).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas includes both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include both associated and nonassociated gas.

At the request of Hess, marketable gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

Primary Economic Assumptions

This report has been prepared using initial prices, expenses, and costs provided by Hess in United States dollars (U.S.\$). Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the reserves reported herein:

Oil and Condensate Prices

Hess has represented that the oil and condensate prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The 12-month average reference prices used were U.S.\$39.77 per barrel for West Texas Intermediate and U.S.\$43.43 per barrel for Brent. Hess supplied appropriate differentials by field to the relevant reference prices and the prices were held constant thereafter. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was U.S.\$37.99 per barrel.

NGL Prices

Hess has represented that the NGL prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was U.S.\$10.82 per barrel of NGL.

Gas Prices

Hess has represented that gas prices were based on reference prices, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The 12-month average reference price for NYMEX was U.S.\$2.16 per million Btu and the UK International Petroleum Exchange reference price was U.S.\$3.22 per million Btu. The gas prices were adjusted for each property using differentials to the NYMEX or UK International Petroleum Exchange reference prices furnished by Hess and held constant thereafter. The volume-weighted average price attributable to the estimated proved reserves was U.S.\$2.52 per thousand cubic feet of gas.

DeGolyer and MacNaughton

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Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, provided by Hess and based on current expenses, were held constant for the lives of the properties. Future capital expenditures were estimated using 2020 values, provided by Hess, and were not adjusted for inflation. In certain cases, future expenditures, either higher or lower than current expenditures, may have been used because of anticipated changes in operating conditions, but no general escalation that might result from inflation was applied. Abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were provided by Hess and were not adjusted for inflation. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of the developed non-producing and undeveloped reserves.

In our opinion, the information relating to estimated proved reserves of oil, condensate, NGL, and gas contained in this report has been

FWE-0040181

prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, and 932235-50-9 of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the FASB and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S–K of the SEC; provided, however, that estimates of proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

Summary of Conclusions

Hess has represented that its estimated net proved reserves attributable to the evaluated properties were based on the definition of proved reserves of the SEC. Hess' estimates of the net proved reserves, as of December 31, 2020, attributable to these properties, which represent 92.0 percent of Hess' reserves on a net equivalent basis, are summarized as follows, expressed in millions of barrels (10⁶bbl), billions of cubic feet (10⁹ft³), and millions of barrels of oil equivalent (10⁶boe):

	Estimated by Hess Net Proved Reserves as of December 31, 2020			
	Oil and Condensate (10 ⁶ bbl)	NGL (10 ⁶ bbl)	Marketable Gas (10 ⁹ ft ³)	Oil Equivalent (10 ⁶ boe)
United States	378	158	601	636
Guyana	204	0	83	218
Malaysia and JDA	6	0	675	118
Other International	88	0	101	105
Total	676	158	1,460	1,077

Notes:

- Marketable gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.
- Net proved fuel gas reserves included as a portion of marketable gas reserves were estimated to be 190 10⁹ft³.
- Joint Development Area is abbreviated JDA.

In comparing the detailed net proved reserves estimates by field prepared by DeGolyer and MacNaughton and by Hess, differences have been found, both positive and negative, resulting in an aggregate difference of less than 1 percent when compared on the basis of net equivalent barrels. It is DeGolyer and MacNaughton's opinion that the total net proved reserves estimates prepared by Hess, as of December 31, 2020, on the properties evaluated and referred to above, when compared on the basis of net equivalent barrels, do not differ materially from those prepared by DeGolyer and MacNaughton.

Hess' oil and gas reserves were estimated assuming the continuation of the current regulatory environment. Foreign oil-producing countries, including members of the Organization of Petroleum Exporting Countries (OPEC), may impose production quotas which limit the supply of oil that can be produced. Generally, these production quotas affect the timing of production, rather than the total volume of oil or gas reserves estimated.

Changes in the regulatory environment by host governments may affect the operating environment and oil and gas reserves estimates of industry participants. Such regulatory changes could include increased mandatory government participation in producing contracts, changes in royalty terms, cancellation or amendment of contract rights, or expropriation or nationalization of property. While the oil and gas industry is subject to regulatory changes that could affect an industry participant's ability to recover its reserves,

DeGolyer and MacNaughton

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neither we nor Hess are aware of any such governmental actions which restrict the recovery of the December 31, 2020, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Hess. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Hess. DeGolyer and MacNaughton has used all data, procedures, assumptions and methods that it considers necessary to prepare this report.

Submitted,

FWE-0040182

/s/ DeGolyer and MacNaughton
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-7

[SEAL] Senior Vice President

/s/ Thomas C. Pence, P.E.
Thomas C. Pence, P.E.

DeGolyer and MacNaughton

DeGolyer and MacNaughton

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CERTIFICATE of QUALIFICATION

I, Thomas C. Pence, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President of DeGolyer and MacNaughton, which firm did prepare the report of third party addressed to Hess Corporation dated February 3, 2021, and that I, as Senior Vice President, was responsible for the preparation of this report of third party.
2. That I attended Texas A&M University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in 1982; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers; and that I have in excess of 38 years of experience in oil and gas reservoir studies and reserves evaluations.

[SEAL] Senior Vice President

/s/ Thomas C. Pence, P.E.
Thomas C. Pence, P.E.

DeGolyer and MacNaughton

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